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BEFORE THE ARIZONA CORPORATION

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IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744.	**DOCKET NO. E-01345A-05-0816**
IN THE MATTER OF THE INQUIRY INTO THE FREQUENCY OF UNPLANNED OUTAGES DURING 2005 AT PALO VERDE NUCLEAR GENERATING STATION, THE CAUSES OF THE OUTAGES, THE PROCUREMENT OF REPLACEMENT POWER AND THE IMPACT OF THE OUTAGES ON ARIZONA PUBLIC SERVICE COMPANY'S CUSTOMERS.	**DOCKET NO. E-01345A-05-0826**
IN THE MATTER OF THE AUDIT OF THE FUEL AND PURCHASED POWER PRACTICES AND COSTS OF THE ARIZONA PUBLIC SERVICE COMPANY.	**DOCKET NO. E-01345A-05-0827**

POST- HEARING REPLY BRIEF OF ARIZONA PUBLIC SERVICE COMPANY

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COMMISSIONERS

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KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744.	DOCKET NO. E-01345A-05-0816
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**POST-HEARING REPLY BRIEF
OF
ARIZONA PUBLIC SERVICE COMPANY**

I.
INTRODUCTION

Arizona Public Service Company ("APS" or "Company") hereby submits its Post-Hearing Reply Brief ("Reply Brief") in the above-captioned matter. APS has extensively briefed the issues in this case in its Initial Post-Hearing Brief ("Initial Brief"). Where there have been no new arguments raised by Commission Staff ("Staff") and Intervenors, the Company will minimize repetition of the discussion of these issues set forth in its Initial Brief. APS's failure to address any issue a second time in its Reply Brief should not be construed as agreeing with statements or conclusions made by Staff and Intervenors in their opening briefs, let alone as conceding a particular issue.

II.
SUMMARY OF POSITION

In its Initial Brief, APS has repeatedly emphasized the challenges it faces in meeting customer growth and raising the massive amounts of capital to provide the infrastructure needed for such growth. Neither can be accomplished unless the Company maintains its credit and improves its earnings. These are obviously important issues to the Company, but APS submits they are even more critical to its customers.

If APS is to provide quality service to a fast growing number of customers at reasonable prices, it simply must have the financial integrity to attract vast amounts of debt and equity capital. The alternative – higher costs and restricted access to capital – is an additional burden APS customers should not have to pay. That is why APS has tried to propose ratemaking techniques and revenue enhancements that have been used around the country, and by this Commission under similar circumstances, to achieve the fundamental and traditional ratemaking goal of just and reasonable rates.

Staff and Intervenors have focused many of their arguments on process and numbers. In doing so, they appear to have lost sight that the ratemaking processes used in a particular circumstance, including all the various adjustments to test period results, are tools to achieving a ratemaking goal – not ratemaking goals in and of themselves. APS urges the Commission to avoid making a similar mistake. The consequences of rote adherence to a "business as usual" approach to ratemaking under the present circumstances are too severe, and the prospects of getting a second chance to fix things in the future are too remote. Those consequences would be nothing less than a financial and economic disaster for APS and its customers.

III.
RATE OF RETURN AND APS'S FINANCIAL INTEGRITY

A. APS's Financial Projections And Related Financial Data Are Highly Relevant And Cannot Be Disregarded By The Commission.

Both Staff and the Residential Utility Consumer Office ("RUCO") take the position that the Commission should disregard the Company's financial forecasts and other financial projections. Staff argues that such financial forecasts are inconsistent with the "historic test year" approach to rate setting used in Arizona and has interjected such inflammatory rhetoric as "skewed" and "manipulation," even referring to the Company's position as mere "tactics." (Arizona Corporation Commission Staff's Initial Post-Hearing Brief ["Staff's Initial Brief"] at 2-3). RUCO similarly argues that "consider[ation] of future financial results" is inconsistent with the "traditional rate making principles" generally followed by the Commission. (Residential Utility Consumer Office's Initial Closing Brief ["RUCO's Initial Brief"] at 2-3).

That position by Staff and RUCO, however, is neither accurate from a legal standpoint nor prudent from a regulatory standpoint. As APS pointed out in its Initial Brief, Arizona law requires that the Commission make the determination that rates are just and reasonable not only at the time they are set, but also during the time that they are in effect. *See Scates v. Arizona Corporation Commission*, 118 Ariz. 531, 533-34, 578 P.2d 612, 614-15 (Ariz. App. 1978). Moreover, the Commission requires that certain financial projections be filed with the Commission as part of any rate proceeding, and Mr. Brandt provided extensive testimony on these points in his Direct Testimony of January 31, 2006. (Tr. Vol. I at 113-14 [Wheeler]; APS Exhibit No. 4 at 5-24 [Brandt]). Although always relevant, these financial projections take on special importance when they indicate that the historical test period analysis may be incapable of producing just and reasonable rates. Indeed, the basic constitutional principles that govern the concept of just and reasonable rates require, among other things, that the Commission determine that the rates are "sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital." *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1942). Thus, it is simply not correct to assert that financial projections and other forecasted financial information should not or cannot be considered by the Commission as part of a rate proceeding. Indeed, they must be considered if the Commission is to satisfy that most fundamental and, yes, "traditional" goal of ratemaking – just and reasonable rates.

Moreover, it would be highly unfortunate for the Commission to disregard the Company's financial forecasts and other projected financial information in this instance. The cash flow problems and earnings shortfalls experienced by the Company in the last several years have driven the Company to the brink of a non-investment, "junk" credit rating. As a consequence, the credit rating agencies have made it clear that they are looking to the outcome of this proceeding to determine what further credit rating action should be taken regarding the Company. (*See* APS's Initial Brief at 15-17). Thus, it is not only appropriate, but also essential for the Commission to evaluate each of the rate proposals made in this proceeding in terms of how they will affect the Company's earnings, cash flow requirements, Funds From Operation ("FFO")-to-debt ratio, and, thus, APS's ability "to maintain and support its credit." *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679, 693 (1923).

As the Company pointed out in its Initial Brief, other regulatory commissions take into consideration the projected impact of a rate decision on a company's financial metrics, including a company's credit standing with major credit rating agencies. (*See* APS's Initial Brief at 10-11.) In each instance, those commissions recognized that consideration of financial forecasts and other projected financial information was necessary in order to assure that a rate decision was fair and reasonable to the company and its customers under all the facts and circumstances. This Commission should not conclude otherwise and, in fact, had considered precisely such anticipated impacts when entering Decision No. 68685 (May 5, 2006) during last year's emergency rate proceeding.

1. The Company's Financial Projections Are Reasonable.

Staff asserts, without any substantiation, that the Company's financial forecasts and other projected financial information may not be accurate or reliable. (Staff's Initial Brief at 3). The evidence in the record, however, is directly to the contrary. Mr. Brandt testified that the financial forecasts and other projected financial information presented by the Company in this proceeding were prepared using the same forecasting methodology that the Company uses in the ordinary course of business, in its regular dealings with rating agencies and financial analysts, and in its filings with the SEC and other government agencies. (Tr. Vol. IV at 769-72 [Brandt]). Moreover, no evidence was presented during the course of this proceeding to suggest that the Company's financial forecasts were unreliable. I ndeed, Mr. Steven Fetter, a former rating agency executive and a former chairman of the Michigan Public Service Commission, testified that he independently analyzed the Company's financial forecasts for 2006 through 2008, including the Company's forecasts based on the Staff and RUCO rate proposals. (APS Exhibit No. 24 at 11 [Fetter]). Mr. Fetter then went on to explain that he believes the Company's forecasts are accurate and that the Company's financial and credit metrics would deteriorate substantially without the full amount of the rate relief requested by the Company. (*Id.* at 12-14).

Perhaps more to the point, any minor discrepancy in the Company forecasts from actual future results (that is, discrepancies only in hindsight) are most likely to be in both directions and pale in comparison with the magnitude of the problem, both in respect to the declining credit metrics and the steady erosion in earned returns. Concerns that APS's FFO/Debt or return on equity might turn out slightly higher or lower than forecast miss the fundamental issues in this proceeding. Simply put, APS is unable to keep up with the burdens imposed by growth (APS's Initial Brief at 13; *see also* Tr. Vol. IV at 782-85 [Brandt]; *see also* APS Exhibit No. 77) without substantial and timely non-fuel rate relief, and from a credit metric standpoint, it can't afford to be non-investment grade, or dragging along the very bottom of investment grade, one small unexpected event away from falling into non-investment grade.

Staff has also contended that because APS's forecasts are based on total Company results and have not been jurisdictionalized, this somehow excuses Staff, and by extension the

Commission, from considering them in determining "just and reasonable" rates. (Staff's Initial Brief at 3). Staff speculates that the earnings shortfalls that are causing the Company's poor financial results for 2007-2008 may be attributable to insufficient non-jurisdictional revenues, specifically transmission revenues. (*Id.*).

In his Supplemental Testimony, Staff witness Dittmer calculated a revenue deficiency for the Company's non-jurisdictional activities during the historical test period of some $50,000,000. (Staff Exhibit No. 39 at 8 [Dittmer]; Staff Exhibit No. 40, Supplemental Schedule JRD-1 [Dittmer]). Aside from the fact that Staff has at best identified $50,000,000 of what is over a $120,000,000 problem,[1] the forecasted data used by APS for 2007-2008 does **not** reflect such a level of revenue deficiency from non-jurisdictional operations.

Much was made in these proceedings about a loss in unregulated trading activities of some $15,000,000[2] that was originally included by accident in APS's jurisdictional test period operations. Yet, Mr. Brandt testified that on a going-forward basis, these non-jurisdictional activities would be profitable and that is what is reflected in the forecasts for 2007-2008. (Tr. Vol. III at 44-45 [Brandt]).

Staff witness Dittmer further agreed that in addition to transmission, the Company had non-jurisdictional sales to small "full-requirements" wholesale customers – the so-called "Majority Districts" and the Town of Wickenburg. (Tr. Vol. XXII at 4237-39 [Dittmer]). The wholesale power agreements with the former were amended subsequent to the historical test period, thus eliminating from the forecasts for 2007-2008 some $19,000,000 of the historical under-recovery in non-jurisdictional costs identified by Mr. Dittmer. (Tr. Vol. XXIV at 4602-04 [Brandt]). Thus, the portion of Mr. Dittmer's estimated historical under-collection of non-jurisdictional costs that could remain in 2007-2008 for alleged transmission service revenue deficiency is no more than $14,000,000 to $18,000,000. (Tr. Vol. XXIV at 4604 [Brandt]). Nearly half of this potential transmission revenue shortfall is tied to the PacifiCorp seasonal

[1] This represents the approximate difference between Staff's non-fuel rate recommendation and that of the Company. It also assumes full adoption of Staff's PSA proposals. Otherwise, the gap between Staff and APS would be some $120,000,000 plus greater. APS's earnings gap for the twelve months ending June 30, 2006, even with a 10.25 percent authorized ROE, was some $134,000,000. (APS Exhibit No. 5, Attachment DEB-10RB [Brandt]).
[2] APS's Initial Brief at 50.

exchange agreement – an agreement previously approved by this Commission as providing net benefits to APS's retail customers. *See* Decision No. 57459 (July 11, 1991). And, the overwhelming portion of any Federal Energy Regulatory Commission ("FERC") authorized transmission rate increase would be flowed directly through to APS retail customers. (Tr. Vol. XXII at 4237 [Dittmer]). In sum, the contention that it is insufficient non-jurisdictional revenues that are at the heart of the Company's financial difficulties, or are even a significant element of those difficulties, simply does not withstand scrutiny and is not a basis for ignoring the dire consequences of inadequate rate relief in this proceeding.

In short, there is no reason to believe that the Company's financial forecasts and other projected financial information presented to the Commission in this proceeding are unreliable or do not accurately reflect the financial impact on the Company of each of the various rate proposals that have been made in this proceeding.

2. The Company's Submission Of More Detailed Financial Information And Projections As Part Of Its Rebuttal Testimony Was Neither Inappropriate Nor Unfair To Staff And RUCO.

There is no justification for Staff's assertion that the Company "laid in wait" for Staff and other parties to expend considerable time and resources before the Company came forth with detailed financial forecasts and other projected financial information. (Staff's Initial Brief at 2). The Company's direct testimony in this proceeding filed in January 2006 contained significant projected financial information and supporting testimony from Mr. Brandt. (APS Exhibit No. 4 at 5-24 [Brandt]). Moreover, the events of the succeeding six to eight months (including the emergency rate proceeding in the Spring of 2006) focused much more attention on the Company's financial forecasts and other projected financial information. Indeed, the emergency rate proceeding – which was an interim step in this rate case – provided Staff and other parties with extensive information about the nature and importance of the Company's financial forecasts.

On July 21, 2006 – approximately six weeks before the Company was to file its rebuttal testimony in this proceeding[3] and prior to the time Staff filed its initial testimony – Chairman

[3] APS Rebuttal Testimony was filed September 15, 2006.

Hatch-Miller sent a letter to the Company requesting that the Company address in this proceeding certain issues that required the Company to rely on financial forecasts and other projected financial information. (APS Exhibit No. 5, Attachment DEB-11RB [Brandt]).

Several weeks later, Staff and Intervenors filed their initial testimony.[4] Such testimony neither addressed those portions of the APS Application and Mr. Brandt's Direct Testimony concerning the future impact of the rates to be set in this proceeding nor made any attempt to provide its own analysis of their recommendations' impact. Thus, Staff and Intervenors did not determine, or even attempt to determine, whether their recommendations satisfied the traditional and constitutionally-mandated ratemaking objective of just and reasonable rates. This was not the result of insufficient time for the preparation of such testimony. Rather, there was apparently never any intent to make the sort of analysis necessary to demonstrate that Staff and Intervenor recommendations would actually produce just and reasonable rates. (APS Exhibit No. 2 at 4-6 [Wheeler]).

Thus, it could not have been a surprise to Staff and other parties, and it certainly was not unfair to them, for the Company to include as part of its rebuttal testimony updated financial information and financial projections of the sort presented in both the original Application and the emergency rate proceeding, as well as other financial projections and estimates in response to the request from Chairman Hatch-Miller. Indeed, it would have been inappropriate for the Company not to provide such updated forecasts and projections. APS has the right to respond to Staff and RUCO revenue requirement proposals that would harm the Company and its customers – proposals that were not tested in any manner to determine whether they would, in fact, produce just and reasonable rates. That is the very essence of rebuttal.

Moreover, at no time after the filing of APS's rebuttal testimony on September 15, 2006, until the conclusion of the testimony in this proceeding on December 15, 2006, did Staff or any other party make an effort to rebut or respond to the financial forecasts or other projected financial information submitted by the Company. Proposals to address the revenue deficiency resulting from the Staff and Intervenor revenue requirement recommendations, such as

[4] Staff's initial testimony was filed August 18, 2006.

Construction Work in Progress ("CWIP") in rate base, accelerated depreciation, and attrition adjustments, are ones that have been previously used by the Commission and are relatively straightforward and simple to understand both as to their purpose and their consequences. They require no specific audit of any figures or complicated calculations and assumptions. Neither Staff nor RUCO's witnesses professed any difficulty on any of these accounts. Under these circumstances, there is simply no merit to the contention that the Company's presentation of such projected financial information in this proceeding was unfair or that such financial information should be disregarded by the Commission.

The eroding credit and earnings of APS are certainly not a "surprise" to anyone. But, even accepting that Staff and RUCO were, nevertheless, "surprised" in some fashion by the scope of the Company's rebuttal testimony, this should not be a reason for failing to take action that is necessary to protect APS and its customers from the dire consequences of clearly insufficient Staff and RUCO revenue requirement recommendations.

3. The Rate Increase Proposals By Staff, RUCO And Certain Intervenors Would Be Insufficient To Allow The Company To Maintain An Investment Grade Credit Rating.

Both Staff and RUCO contend that the need for a rate increase in this case "is entirely driven by increased fuel and purchased power expenses." (*See* Staff's Initial Brief at 5). And both Staff and RUCO, while agreeing to a rate increase for increased fuel and purchased power costs, call for an actual **reduction** in existing rates with respect to non-fuel expenses of the Company even though the uncontroverted evidence shows that such costs are rising faster than revenues and that the resulting attrition will prevent APS from earning any of the recommended equity returns. (*See* APS's Initial Brief at 1). RUCO's recommendations even make matters worse than do those of Staff by proposing to decrease the Company's allowed return on its invested equity ("ROE"). As Mr. Brandt and Mr. Fetter both made clear, such a result – or anything close to it - would almost certainly result in a downgrade of the Company's credit rating to "junk" status. (APS's Initial Brief at 11-15).

Even under the Company's rate proposal, the Company's near-minimum FFO/Debt ratio at year-end 2006 improves only slightly in 2007. (APS Exhibit No. 5, Attachment DEB-1RB [Brandt]). But the Company's marginal year-end 2006 FFO/Debt ratio weakens and declines considerably in 2007 under both the Staff and RUCO rate proposals, falling several points under the minimum ratio specified by Standard & Poor's ("S&P") for an investment-grade credit rating. (*Id.*, Attachments DEB-2RB and DEB-3RB [Brandt]). Under these circumstances, the rate proposals by Staff and RUCO (as well as the limited rate increase proposed by Phelps Dodge/Arizonans for Electric Choice and Competition ("Phelps Dodge/AECC") simply ignore the reality that such proposals would not sufficiently address the cash flow problems and would actually exacerbate the earnings shortfalls that have beset the Company in recent years and would result in the Company being downgraded to a "junk" credit rating. Indeed, none of these parties even bothers to address in their Initial Briefs the impact of their rate proposals on the Company's financial metrics or credit standing.

S&P described the Commission's actions in 2006 relating to the Company's cash flow problems and weakened financial metrics as being "generally constructive," but S&P made clear several times since then that it is looking for "sustained regulatory support that addresses permanent rate relief..." (APS Exhibit No. 5, Attachment DEB-5RB [Brandt].) An acceptance by the Commission of anything close to the rate proposals of Staff, RUCO or even Phelps Dodge/AECC would send an immediate negative message to the investment community and the credit rating agencies. And, as unpleasant as that message may be to hear, and as arbitrary as it may seem to some, to ignore the message being sent from S&P and others would place APS customers in a far worse position. Rather, now is the time to address the substance behind the message.

B. <u>The Company's Requested Capital Structure And Allowed ROE Should Be Approved By The Commission.</u>

1. The Commission Should Approve The Capital Structure Proposed By APS.

In its Initial Brief at 41, Staff has accepted APS's proposed capital structure for purposes of determining APS's cost of capital in this proceeding. RUCO, on the other hand, continues to claim that a hypothetical 50/50 debt-to-equity ratio should be adopted by the Commission. RUCO is the only party asserting this position.

As APS explained in its Initial Brief, RUCO's capital structure proposal is based on several erroneous assumptions, not the least of which is that APS's requested capital structure is somehow different than its historical capitalization. (APS's Initial Brief at 23-24). Moreover, Dr. Avera explained that Mr. Hill's analysis of industry capitalization ratios improperly included short-term debt and financial ratios of companies with "junk" credit ratings, both of which substantially distort the results. (APS Exhibit No. 42 at 66-69 [Avera]). Nowhere in its Initial Brief does RUCO deal with these errors. Instead, RUCO simply makes the unsubstantiated and wholly unsupported assertion that APS's requested capital structure would likely result in "financial cross-subsidization of Pinnacle West by APS' ratepayers." (RUCO's Initial Brief at 26).

As Mr. Brandt explained, in the current capital environment and given APS's current growth cycle, RUCO's capital structure proposal would result in a financially weaker APS and would likely reduce APS's credit metrics to non-investment grade. (APS Exhibit No. 6 at 19 [Brandt]). There is no justifiable reason for the Commission to take such a step, and, therefore, RUCO's proposed capital structure should be rejected by the Commission.

2. An Allowed ROE of 11.5 Percent Is Fair And Reasonable.

Conspicuously absent from the discussions of allowed rate of return by Staff and RUCO in their Initial Briefs is any mention of investor expectations, recent trends in allowed ROE's granted to other electric utilities, and the constitutional requirement that a fair and reasonable allowed ROE has to be coupled with a reasonable opportunity to actually earn that allowed ROE. Instead, Staff and RUCO simply repeat the heavy reliance by their respective witnesses (Mr. Parcell and Mr. Hill) on their particular version of the discounted cash flow ("DCF") model for estimating cost of capital. It bears repeating, however, that such heavy reliance on that DCF model has been repeatedly criticized by other regulatory commissions in recent years (APS Exhibit No. 42 at 46-49 [Avera]), with one commission stating that "the constant discounted cash flow model [used by both Mr. Parcell and Mr. Hill] does not provide reliable results." (Final

Order, Docket No. 9945, Public Utility Commission of Texas [Feb. 6, 1992]). In contrast, Dr. Avera used a more balanced approach to estimating the cost of capital, including the very same multi-stage DCF model that recently was adopted by this Commission in Docket No. W-01303A-05-0405. (APS Exhibit No. 42 at 19-28 [Avera]; APS Exhibit No. 43 at 8 [Avera]). Just the use of that same multi-stage DCF model in this instance (rather than the single-stage discounted DCF model) would result in an allowed ROE for APS of 11.2 percent (before considering an allowance for flotation costs). (APS Exhibit No. 42 at 19-28 [Avera]; APS Exhibit No. 43 at 8 [Avera]).

Investor expectations, which Staff and RUCO completely ignore, are also an important factor in deciding what a fair and reasonable ROE would be and bear heavily on a company's credit rating. As Lehman Brothers stated just a few months ago:

> The [ROE] recommendations [of Staff and RUCO] mark the likely worst case in this proceeding. We view fair treatment by the ACC as essential to APS' investment grade rating and attraction to equity investors. Should the final order reflect financial parameters approximating these [Staff and RUCO] filings, it would be difficult for Arizona Public Service . . . to maintain investment grade ratings or provide support for the current stock value in our view.

(APS Exhibit No. 5, Attachment DEB-19RB [Brandt]).

Moreover, it is undisputed that APS has not earned its existing allowed ROE of 10.25 percent for several years, and that its actual rate of return as of June 30, 2006 was a mere 5.7 percent – a $134,000,000 shortfall. (*See* APS Exhibit No. 5, Attachment DEB-10RB [Brandt]; APS Initial Brief Exhibit 4). Thus, the contention by Staff that keeping the allowed ROE at 10.25 percent (let alone reducing it to 9.25 percent as suggested by RUCO) ignores the reality that APS will not have a reasonable opportunity to earn that ROE – something that both the Staff and RUCO witnesses did not dispute. (*See* APS's Initial Brief at 25).

Dr. Avera and the Company have presented compelling reasons why APS's allowed ROE should be increased to at least 11.5 percent, and it would be unjust under all the facts and circumstances for the Commission to accept the ROE proposals of Staff and RUCO. Other regulatory commissions have recognized the need to increase allowed ROE's under current market conditions (*see e.g.*, APS Initial Brief at Exhibit 3), and this Commission should do likewise.

C. <u>The Commission Should Implement The Revenue Enhancements Proposed By The Company.</u>

Although Staff concedes that the Company's proposals to include CWIP in rate base and include an allowance for accelerated depreciation might make sense and would "eventually yield reductions in rates for future ratepayers," Staff and RUCO generally oppose any of the three revenue enhancements (including an earnings attrition allowance) proposed by the Company in response to **both** their own revenue requirements recommendations, which where demonstrably insufficient, and the July 21, 2006, letter from Chairman Hatch-Miller asking the Company to discuss such types of proposals. (Staff's Initial Brief at 5). Staff's entire discussion of these proposals amounts to one-and-a-half pages of its Initial Brief, and RUCO's discussion covers approximately 2 pages. (*Id.* at 4-5; RUCO's Initial Brief at 46-47). The Commission, however, should not be so quick to dismiss the Company's proposals.

As APS discussed in its Initial Brief at 26-31, these proposed adjustments serve the purpose of improving the Company's cash flow either without increasing the Company's profits (in the case of CWIP and accelerated depreciation) or (in the case of an attrition allowance) providing the Company with a reasonable opportunity to earn its allowed ROE in the face of demonstrated earnings attrition stemming from the lag in recovering the huge capital expenditures required to meet the Company's rapidly growing customer base. (APS's Initial Brief at 26-31). These are important considerations for the Commission from the standpoint of the Company's important credit metrics, sound regulatory policy, and the constitutional requirement of earning a just and reasonable ROE. They are considerations distinctly absent from the Staff and RUCO revenue requirements recommendations. And the Company presumes that such considerations lay behind why Chairman Hatch-Miller asked that proposals of this nature be discussed in this proceeding. To dismiss these proposals without providing some alternatives, as Staff and RUCO essentially do, is unjustified. If the Company's requested rate increase was significantly reduced along with rejection of these proposed revenue enhancement mechanisms, it would raise very serious questions about whether the rates fixed by the Commission could be defended as just and reasonable as a matter of law.

Consistent with the concerns APS has raised in response to Staff's and RUCO's recommendations and also the objectives that prompted Chairman Hatch-Miller to request discussion of such mechanisms in the first place, these revenue enhancements proposed by the Company can and should be used by the Commission to provide the cash flow that the Company has demonstrated that it needs, and to correct the undisputed earnings attrition that the Company has shown it has experienced in the past several years. (*See* APS Initial Brief Exhibit 4 and the accompanying text). They reflect mechanisms that have a proven track record in Arizona and other jurisdictions of addressing the problems now facing APS and its customers. And now and in the future, not just the Company, but also its customers, will benefit from implementation of these proposals.

IV.
BASE FUEL COST AND POWER SUPPLY ADJUSTOR

A. Power Supply Adjustor ("PSA").

APS agrees that Staff's proposed "prospective" PSA is superior to its own PSA proposal in ensuring the timely and full recovery of fuel and purchased power costs. (Tr. Vol. XXIII at 4326-27 [Rumolo]). That conclusion, however, is premised upon several important factors:

1. The "forward component" must be set in **this** proceeding and become effective **at the same time** base rates are made effective.

2. The "forward component" must be set at the difference between the Base Fuel Cost established in this case by the Commission and 3.2491¢/kWh (which would make such "forward component" zero under the Company's proposed Base Fuel Cost).

3. The 90/10 penalty provision would be abolished.

4. The charges authorized under the current PSA structure (the February 1, 2007 Annual Adjustor, the Step 1 PSA Surcharge, and the Step 2 PSA Surcharge [to the extent authorized]) must be allowed to run their course and not be terminated and rolled into a 2008 "historic component," as was suggested in Staff's original Plan Of Administration ("POA"). This is consistent with Staff witness Antonuk's testimony at the hearing. (Tr. Vol. XXI at 3870-75 [Antonuk]).

5. Some provision must be made for broker fees. The most obvious solution would be to include them in the recoverable costs under the PSA. A second, but less preferable, option would be to treat them as a separate line item in the Company's non-fuel operating expenses. (APS's Initial Brief at 37).

With these provisos, the Company could support Staff's PSA proposal and its POA for such proposal.

B. <u>Base Fuel Cost.</u>

APS continues to urge adoption of a realistic Base Fuel Cost. The only Base Fuel Cost number in this case that represents updated fuel prices and the conditions that will be in effect when the new Base Fuel Cost becomes effective (*i.e.*, 2007) is that contained in Mr. Ewen's Rejoinder Testimony, or 3.2491¢/kWh. (APS Exhibit No. 18 at 2 [Ewen]).

In Staff's brief, Staff presents several criticisms by Staff witness Antonuk of the Company's Base Fuel Cost calculations. (Staff's Initial Brief at 7). However, **all** of them are of the Base Fuel Cost presented either in Mr. Ewen's **Direct or Rebuttal Testimony**. On **Rejoinder**, Mr. Ewen modified his recommendation using **all** of the suggestions of Staff witness Antonuk in his surrebuttal testimony, which is the basis of the Company's Base Fuel Cost recommendation in this proceeding, *i.e.*, 3.2491¢/ kWh. (APS's Initial Brief at 33; APS Exhibit No. 18 at 4-5 [Ewen]). In his Supplemental Testimony, Mr. Antonuk endorsed Mr. Ewen's calculation, stating:

> [T]his [the APS Rejoinder forecast of 2007 fuel costs], we conclude, is comprehensively and logically structured, consistent with reasonable expectations about system assets, and reflective of market price expectations current as of its vintage.

(Staff Exhibit No. 30 at 23 [Antonuk]). He went on to recommend that Mr. Ewen's number be adopted by the Commission in establishing the "forward component" of Staff's PSA for 2007. (*Id.* at 3; Tr. Vol. XXI at 3993 [Antonuk]).

The question becomes: if Mr. Ewen's Rejoinder Testimony calculation of 2007 fuel costs is sufficiently accurate for adoption as the "forward component" under Staff's PSA proposal, why should it not be used to establish a new Base Fuel Cost? Of course, there is **no** reason, and Staff offers none in its opening brief. In either event, any deviation of actual 2007 fuel costs from the 3.2491¢/kWh Base Fuel Cost proposed by APS (expected to be an under-recovery approaching $60,000,000 for the reasons discussed at page 33 of the Company's Initial Brief) will be captured by the PSA. Thus, there is no possibility of over-recovery by APS of 2007 fuel costs under the APS Base Fuel Cost proposal.

Whether the PSA remains a retrospective reconciliation of already incurred fuel costs, as urged by RUCO and Phelps Dodge/AECC, or a prospective mechanism to recover fuel costs as incurred (the Staff recommendation, which APS supports with the provisos discussed above), the Base Fuel Cost should be set as close as possible to current expectations of fuel and purchased power costs during the period it first becomes effective. Only the Base Fuel Cost provided in Mr. Ewen's Rejoinder Testimony accomplishes that goal, and it should be adopted irrespective of what other changes to the PSA are accepted by the Commission.

V.
OPERATING INCOME AND RATE BASE ADJUSTMENTS

A. Jurisdictional Allocation Of Rate Base And Operating Income Adjustments.

APS had indicated in its Initial Brief that there were no jurisdictional allocation issues. Neither Staff nor RUCO had taken issue with the Company's jurisdictional allocations in their pre-filed testimony.[5] However, upon examining the various jurisdictional calculations of their final revenue requirement recommendations, as submitted with their opening briefs, APS has determined that there are some differences in the jurisdictional allocation of specific pro forma adjustments, both contested and uncontested, in this proceeding. The differences are not very significant and, frankly, they go in both directions – sometimes slightly favoring the Company and in other instances, going to the Company's disadvantage. Attached as APS Reply Brief Exhibit 1 is a list of the specific pro forma adjustments and the jurisdictional factors used by APS, Staff and RUCO for allocating such adjustment.

The record contains no testimony explaining or justifying the jurisdictional allocation factors used by Staff and RUCO, and, in some instances (*e.g.*, the allocation of over 100 percent of an adjustment to the ACC's jurisdiction), they are clearly erroneous. However, as a practical

[5] There was, however, significant disagreement over inter-class cost allocations.

matter, the Company's allocation factors should be used for one simple reason. The APS jurisdictional allocations determined how much of an expense, revenue or rate base element was included in the Company's request. To the extent a portion of such expense, revenue item, or rate base element is disallowed by the Commission, there is no reason to disallow more or less than was included in the Company's filing in the first instance. Thus, APS urges the Commission to adopt its jurisdictional allocation factors.

B. Uncontested Adjustments.

There is agreement among the Parties for many of the Company's adjustments, as discussed in the Company's Initial Brief. To reiterate, the Parties have no dispute regarding the following adjustments:

1. Uncontested Rate Base Adjustments.

- Sundance Units.[6]
- Spent Nuclear Fuel Storage.
- Palo Verde Unit 1 Steam Generators.
- Long Term Disability (SFAS 112).
- Regulatory Disallowance of West Phoenix Unit 4.

2. Uncontested Operating Income Adjustments.

- Spent Nuclear Fuel Storage.[7]
- Nuclear Decommissioning.[8]
- Four Corners Coal Reclamation.
- Annualized Payroll.
- Regulatory Disallowance for West Phoenix Unit 4.
- Regulatory Assessments and Franchise Fees.

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[6] The Sundance Units were acquired on May 13, 2005 for $189,500,000 and APS seeks to include this amount as part of its rate base. (APS Exhibit No. 56 at 16 [Rockenberger]). Therefore, no pro forma adjustment is necessary.

[7] Consistent with the treatment in Decision No. 67744, the Company is specifically requesting that the Commission include the "Schedule of Amounts to Be Deposited in the Decommission Trusts" to its final Decision in this case. (*See* Appendix I, Decision No. 67744; APS Exhibit No. 56 at Attachment LLR-3 [Rockenberger]).

[8] The Company is requesting that the Commission's Decision in this case also specifically provide for approval of the $19,211,000 annual level of decommissioning funding and that the Commission Decision include Attachment LLR-3 from APS Exhibit No. 56 [Rockenberger].

- Base Rate Component for EPS.
- Interest on Customer Deposits.
- Amortization of Regulatory Assets.
- PWEC Loan.
- Tax Consulting Fees.
- Out of Period Income Tax Adjustments.
- Miscellaneous Adjustments.
- Pension Expense (not including the Company's proposal to amortize the unfunded pension liability over five years).
- Post Retirement Medical Benefits.
- Administrative and General.
- Unregulated APS Marketing and Trading Activity.
- Palo Verde Unit 1 Steam Generators Depreciation.
- Normalized Non-Nuclear Maintenance Expense (except as discussed in the Contested Operating Income Adjustments section regarding the Sundance and PWEC Units).
- Normalized Nuclear Maintenance Expense.
- Annualized Customer Levels.
- Normalized Weather Conditions.
- Annualized Revenues for 4/1/05 ACC Rate Levels.
- E-3/E-4 Promotional Expense.
- Schedule 1 Changes.
- Federal and State Income Tax.
- Depreciation Rates and Depreciation Expense.[9]

3. Other Uncontested Revenue Requirement Issues.

- Addition of Incremental EPS Surcharge.

Each of the above adjustments was reflected in APS Initial Brief Exhibit 5 and the APS revenue requirement, as shown on APS Initial Brief Exhibit 1. Thus, no incremental adjustments

[9] APS also asks that the Commission specifically approve in its order the depreciation and amortization rates used by the Company.

to the Company's rate base, operating income, or revenue requirement are required for the adoption by the Commission of these uncontested adjustments.

C. Contested Rate Base Adjustments.

1. Allowance For Cash Working Capital.

As noted in the Company's Initial Brief at 41-44, the principal issues here are whether to properly reflect the lag in the recovery of depreciation and deferred taxes in the rate setting process, and conversely, whether the lag in the payment of interest should be recognized without either an upward adjustment to ROE to reflect the loss of a portion of the equity return, or the inclusion of the lag in return (operating income) as an offset to the impact of interest on cash working capital.[10] (APS's Initial Brief at 43). Staff and RUCO presented essentially three rationales for their respective positions:

1. The Commission in Decision No. 55931 (April 1, 1988) rejected the inclusion of depreciation and deferred taxes in cash working capital and approved the inclusion of interest expense;[11]

2. Although the depreciation and deferred tax reserves at the end of the test period were not fully recovered in cash receipts as of the same date, APS eventually received such cash receipts; and,

3. Although the depreciation and deferred tax reserves at the end of the test period were not fully recovered in cash receipts, neither did all the plant in service reflect cash outlays.

The first of the above arguments is, of course, an accurate recitation of that 1988 Decision. But that does not tell the Commission anything about whether Decision No. 55931 was rightly decided on these points. Neither does Decision No. 55931 prevent the Commission

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[10] Staff and RUCO have briefed only the issues of depreciation, deferred taxes and interest. (Staff's Initial Brief at 16-18; RUCO's Initial Brief at 10-12). Thus, APS will not address the remaining issues of amortized nuclear fuel expense and insurance expense. (APS's Initial Brief at 42-44).

[11] In its Brief, Staff noted that APS witness Rockenberger made reference to Decision No. 55931 and stated that the Company's Lead/Lag study methodology was consistent with that required by that Decision. To clarify the record, Ms. Rockenberger stated that the Company's Lead/Lag study did depart from Decision 55931 with respect to depreciation, deferred taxes and interest. She then reiterated the Company's belief that including depreciation and deferred taxes, and excluding interest was appropriate. (Tr. Vol. XIII at 2663 [Rockenberger]). Ms. Rockenberger's testimony referenced the above decision only to indicate that the Company had presented a lead/lag study, which was specifically required by Decision No. 55931, even though not otherwise required by the Commission's Standard Filing Requirements.

from reconsidering its views in this proceeding if it believes the Company's arguments are persuasive given the critical cash flow issues facing APS.

The second contention is also true. But it is also irrelevant for the reasons explained by Company witness Balluff in his Rebuttal Testimony:

> Q. WHAT IS THE RELEVANCE OF STAFF'S STATEMENT ON DEPRECIATION AND DEFERRED INCOME TAXES?
>
> A. There is none – Mr. Dittmer's statement is not relevant to the issue at hand. Of course depreciation and deferred income taxes recorded by September 30, 2005 will be collected by October 2006. But that is true with **all** other expenses with a revenue lag. APS calculated a revenue lag of over 35 days, and it is that lag in recovery and not the fact that costs are eventually recovered, which is relevant to cash working capital requirements. If his statement has any relevance, there would be no reason to do a lead/lag study.

(APS Exhibit No. 66 at 3-4 [Balluff] (emphasis in original)).

The third point raised by Staff is its only substantive argument against the Company's position. However, as noted by Mr. Balluff in his Rejoinder Testimony, the amount of plant not representing actual cash outlays as of September 30, 2005 was less than $2,000,000 – far less than the impact of excluding depreciation and deferred taxes from the lead/lag computation of cash working capital. (APS Exhibit No. 67 at 2 [Balluff]). And even that less than $2,000,000 is dwarfed by the lag in recovery of additional test period plant costs that will occur from their actual in service date to the date rates become effective in this case, a lag reflected in neither the Company nor Staff rate base numbers. (*Id.* at 2-3).

The well known authority, *Accounting for Public Utilities*, cited at page 41 of the Company's Initial Brief, addresses the issue of depreciation and deferred taxes as part of cash working capital in some detail:

> [2] Depreciation and Deferred Tax Lag
>
> From figure 5-3 [attached hereto as "APS Reply Brief Exhibit 2"], it can be seen that after having determined the overall lag in operation and maintenance expenses, the next item, depreciation, reflects a zero lag. This zero lag is used because accumulated depreciation, the contra account to the depreciation provision [expense], is deducted from rate base. However, on occasion, the issue has been raised that depreciation is a non-cash charge and therefore cannot produce a need for cash working capital. While it is true that recording

> depreciation does not require the expenditure of cash at the time the expense is recorded and charged to the customer, cash **was** expended at the time the property was acquired, and the recorded depreciation is used to reduce the investment in that property even though approximately one-and-one-half month's depreciation (equivalent to the revenue lag) has not yet been received from the consumer.
>
> It can be noted from figure 5-3 that a zero lag has also been used for deferred income taxes. The same issue is involved with respect to provisions for deferred income taxes which are used to reduce rate base as that for depreciation. In the case of deferred income taxes, the balance also includes approximately 45 days of uncollected tax provisions. These provisions are used to reduce other investments made for rate base components even though the last 45 days have not yet been received from the consumer.

ROBERT L. HAHNE & GREGORY E. ALIFF, ACCOUNTING FOR PUBLIC UTILITIES 5-2 (1990) (emphasis added).

Although APS has been able to reduce its revenue lag to 35 days from the 45 days assumed in the above example, the principle is the same regarding the necessity of including these expense components in the calculation of cash working capital. Alternatively, the Commission could make a direct downward adjustment of equal magnitude to the depreciation and deferred tax reserves. (APS Exhibit No. 66 at 4 [Balluff]).

Finally, with regard to interest, Messrs. Hahne and Aliff state:

> The operating income component is subject to a wide difference of opinion in treatment when lead-lag studies are prepared. From a theoretical standpoint, operating income is earned when service is provided, and the operating income is the property of the investors in the company when earned. This view would recognize a cash working capital requirement for the lag in receipt of operating income. Such a requirement is equal to the revenue lag days times an amount equal to one day's operating income. The amount for interest or preferred dividends would not be offset, since those amounts are paid from investor-supplied funds (operating income). At the opposite end of the spectrum are those who take the position that a source of cash working capital exists in the delay in disbursement of interest and preferred dividends without any consideration of the lag in the receipt of operating income.
>
> In recent years, few commissions have accepted either of these opposing points of view. Usually, the decisions are somewhere between the two poles. **The most prevalent is probably to not consider the operating income component in the lead-lag study, which results in not recognizing a need for cash working capital to cover operating income and not recognizing accruals of interest and preferred dividends as a source of cash working capital.**
>
> The procedure of ignoring operating income generally produces

> approximately the same effect as does the procedure of recognizing the lag in collecting the operating income component of revenues while also recognizing a lag in the payment of interest expense and preferred dividends. The majority of commissions considering the question have adopted one of these latter two methodologies.

ROBERT L. HAHNE & GREGORY E. ALIFF, ACCOUNTING FOR PUBLIC UTILITIES 5-2 (1990) (emphasis added).

The "lag" in the receipt of operating income referenced above is the lag in overall return discussed in the Company's Initial Brief (APS's Initial Brief at 43) and by Mr. Balluff in his Rebuttal Testimony. (APS Exhibit 66 at 11 [Balluff]). As noted, most jurisdictions either include both that operating income lag and interest or exclude both, as has APS. Thus, Decision No. 55931 is out of step with what would appear to be the general treatment of cash working capital throughout the country.

All of the positions expressed by the above authoritative text are consistent with the Company's testimony herein. In contrast, Mr. Dittmer's and Ms. Diaz Cortez's opinions on the subject are merely that, opinions unsupported by any authority other than a 1988 Decision that provided no analysis or rationale for its findings relative to cash working capital.

2. Bark Beetle Regulatory Asset.

In its Initial Brief, RUCO continued to oppose the Company's adjustment to the Test Year balance of regulatory deferrals through December 31, 2006. RUCO has argued that estimates of the amount that the regulatory asset would be at some future time were not known and measurable. In addition, RUCO argued that such an adjustment did not comply with the matching principal because those expenses would not be properly matched in time with other elements of rate base, revenues and expenses. (RUCO's Initial Brief at 7). The Company disagrees with RUCO's position. The Company's financial projections, which were based on actual costs as of July 31, 2006 and included transportation costs related to remediation activities, indicated that the Company will clearly have more in deferred costs than was estimated in the January 2006 filing. It is appropriate under the matching principal to use estimated costs to ensure that the rates in effect provide for the amortization of the actual costs incurred by year-end 2006. (APS Exhibit No. 57 at 14 [Rockenberger]).

Staff, on the other hand, has no dispute with the Company's deferral through December 31, 2006, but has asserted that the Company should not have begun deferring bark beetle remediation expenditures retroactively to January 1, 2005, because that was three months before the effective date of Decision No. 67744, which authorized the deferral of the remediation costs. (Staff's Initial Brief at 22-24). The Company continues to assert that the language of Decision No. 67744, which states that "APS is authorized to defer for later recovery the reasonable and prudent direct costs of bark beetle remediation that exceed the test year levels of tree and brush control," indicates that the Commission, as well as the Parties to the Settlement Agreement that was adopted by that Decision, intended for the Company to have a full year of cost recovery for 2005. (Decision No. 67744 at 31).

As discussed in its Initial Brief at 44, the Company position that an estimated Total Company deferral of distribution-related bark beetle remediation costs of $11,622,000 at December 31, 2006, which adds $4,360,000 to APS's rate base, is the appropriate adjustment. (*See* APS Initial Brief Exhibit 5, Schedule B-2, Column 5).[12]

3. Investment Tax Credit.

In its Initial Brief, Staff claimed that the only rebuttal argument presented by the Company supporting its treatment of the Investment Tax Credits ("ITC") was the issue of Internal Revenue Service normalization violations. Thus, Staff appears to contend that it had no opportunity to respond to the Company's arguments (other than normalization requirements). (Staff's Initial Brief at 30-31). Such contention is inaccurate in two major respects.

This statement by Staff omitted the two additional and compelling arguments that Mr. Froggatt made in his prefiled Rebuttal Testimony:

> Q. WHY DO YOU BELIEVE BOTH THE FEES AND THE TAX CREDITS ARE APPROPRIATELY REMOVED FROM REGULATED COST OF SERVICE AND RATE BASE?

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[12] The Company's rate base calculation was reduced from its original filing of $6,115,000 (APS Exhibit No. 56, Attachment LLR-1-5 [Rockenberger]) by $1,755,000, which includes a reduction of $2,793,000 for accumulated deferred income taxes, partially offset by a $1,038,000 rate base increase comprised of a $705,000 addition to correct the calculation for the actual September 30, 2005, deferred bark beetle remediation costs, and a $333,000 addition to increase the projected bark beetle remediation cost deferrals through December 31, 2006. (APS Exhibit No. 57 at 13-14 [Rockenberger]).

> A. First, as I discussed above in full agreement with Staff and RUCO, both the fees and related tax credits are non-recurring and clearly unrelated to the test year.
>
> Second, as part of the 1994 settlement (Docket No. U-1345-94-120, Decision No. 58644), the Company was authorized to accelerate below the line amortization of all deferred ITC's in order to fully amortize those credits over a five year period beginning in 1995. Staff's proposed adjustment is not consistent with this treatment.

(APS Exhibit No. 49 at 8-9 [Froggatt]).

Staff was also afforded the ability to present supplemental testimony even after the filing of APS rejoinder testimony and did so in several instances. This provided Staff with at least **two** opportunities to rebut the Company's arguments that both Decision No. 58644 and the non-recurring out-of-period nature of these ITCs preclude adoption of Staff's adjustment.

As discussed in its Initial Brief at 44-46, the Company continues to assert that the ITCs at issue are non-recurring, unrelated to the Test Year, and governed by the provisions of Decision No. 58644. Therefore, these ITCs should not be included in the regulated cost of service.

4. Supplemental Executive Retirement Program ("SERP").

RUCO's adjustment to remove both the deferred credit and associated deferred taxes related to the Company's SERP has the effect of increasing rate base by $30,600,000. (*See* RUCO's Initial Brief at 9).[13] Although this proposal results in an increase in the Company's rate base, APS must oppose the adjustment to be consistent with its position that the associated operating expense should be recognized in cost of service.

D. <u>Contested Operating Income Adjustments.</u>

1. Bark Beetle Remediation.

For reasons discussed previously, the Company maintains its position that its pro forma adjustment to increase Test Year costs, and, thus, reducing pre-tax operating income by $1,548,000 to reflect that annual expense level, is correct and should be adopted. (APS Exhibit

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[13] Although the RUCO Brief also refers to its adjustment as "removing" these items from rate base, a deferred credit such as SERP in any case would be a rate base offset if allowed as a cost of service element. The deferred tax impact of a deferred credit is to reduce the accumulated deferred tax balance, and, thus, the net of these two is a rate base addition.

No. 57 at 14 [Rockenberger]; *Id.* at Attachment LLR-4-2RB; *see* APS Initial Brief Exhibit 5, Schedule C-2, Column 16).

2. Sundance Units.

APS discussed the RUCO adjustment to Sundance Units Operations & Maintenance ("O&M") in its Initial Brief at 55-56. The Company would only add that the conclusions of Staff's consultant, The Liberty Consulting Group, concerning the appropriate level of O&M at the Company's gas-fired units, including Sundance and the former Pinnacle West Energy Company ("PWEC") units,[14] should not be so cavalierly dismissed by the Commission as they have been by RUCO. (RUCO's Initial Brief at 18).

On the issue of non-routine O&M, Staff's Initial Brief identifies several "reasons" for disregarding in the case of Sundance the process used to establish overhaul expense for all of the other APS generating units. APS will address them in the order presented.

The first is that the overhauls will not occur during the period that rates from this proceeding are likely to be in effect. (Staff's Initial Brief at 20). However, the same could be said for most of the Company's generating units, depending on how long one anticipates rates from this case will be in effect. As was explained in the Company's Initial Brief at 55-56, the methodology historically employed by the Commission to recognize these costs over the anticipated maintenance overhaul schedule does not depend on when the overhaul actually takes place (*i.e.*, in the test period, a year earlier, a year later, or 12 years later).

The second concern is that under APS's proposal, having paid for a pro rata portion of the Sundance overhaul costs in rates today, customers would pay a second time in some future rate proceeding for the same costs. (Staff's Initial Brief at 20). Again, as explained in APS's Initial Brief, this cannot happen unless the Commission abandons, which abandonment has been recommended by Staff, its traditional practice of spreading costs pro rata across the maintenance cycle of a unit. However, if making some sort of specific accounting accrual of these costs, as proposed by Staff, will resolve this issue and permit these costs to be recovered from those APS

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[14] *See* Staff Exhibit 33 at 92 [Fuel Audit].

customers receiving the benefit of Sundance's current operations, the Company would not object to such an accounting procedure. (*See generally id.*).

Staff next contends that because the Sundance non-routine maintenance expense is based on a forecast, it is somehow distinguishable from APS units with historical overhaul experience. (*Id.* at 21). However, Staff witness Dittmer admitted that Staff had used similar forecasts for the PWEC units in the last APS rate proceeding and had used forecasts for Palo Verde in earlier APS rate cases. (Tr. Vol. XXII at 4220-21 [Dittmer]). Again, Staff has provided no basis for its dissimilar treatment of Sundance overhaul costs.

3. PWEC Units.

APS addressed the substantive argument raised by RUCO concerning the variable component of O&M relative to the former PWEC generating units in its Initial Brief at 57. Phelps Dodge/AECC has, in its Initial Brief, reiterated its argument that APS should somehow be bound to the level of O&M used for the former PWEC units in the last rate proceeding. That prior docket used a 2002 test period. The former PWEC units operate in a different mode now that they are APS units. (Staff Exhibit No. 33 at 91-92, 105 [Fuel Audit]). Without any analysis or evidentiary support, there is simply no basis to assume that costs have not increased in the over four years since that prior test period. To state that the resolution of the issue of rate-basing the PWEC units would have been different had the Commission believed that the future costs of operating the PWEC units would increase is not only conjecture, but it requires one to believe the Commission was somehow unaware of the fact that utility costs, including plant O&M, increase over time. APS cannot attribute such naivety to either the Commission or the parties to the 2004 APS Settlement, including Phelps Dodge/AECC, and again urges the Commission to reject all adjustments to the former PWEC Units O&M.

4. Advertising And Business Meals.

In large part, there is little dispute regarding the Company's advertising adjustment. In its initial filing, APS had reduced Test Year expenses for the advertising expenses that were, at least in part, associated with "branding," which is consistent with Staff's recommendations in the Company's prior rate case. (APS Exhibit No. 56 at 25 [Rockenberger]). In its rebuttal case, APS agreed to exclude an additional $437,000 of marketing and sponsorship costs that Staff had identified. (APS Exhibit No. 57 at 23 [Rockenberger]). The Company also agreed to an additional $66,000 reduction in advertising expenses that were identified by RUCO. (*Id.* at 23-24). There are only two elements of RUCO's recommendation that the Company opposes. The first is a $100,000 advertising cost that Staff recommended be disallowed. The Company had already accepted Staff's recommendation on this item. To accept RUCO's recommendation to reduce expenses for the same item would result in reducing advertising twice for the same $100,000 expense. The second issue is the cost of business lunches that are provided in some circumstances when employees are required to work through the lunch hour. As discussed in its Initial Brief at 58-59, these business lunches are legitimate business expenses. Because none of the Parties have contested these issues in their Initial Briefs, the Company has no further arguments to which it can respond.

5. Underfunded Pension Liability.

As discussed in its Initial Brief at 59-62, the Company asserts that the evidence in this case supports the Company's final adjustment to decrease its pre-tax Test Year operating income in the amount of $41,166,000,[15] which represents the Company's ACC Jurisdictional pre-tax adjustment to its underfunded pension account. (*See* APS Initial Brief Exhibit 5, Schedule C-2, Column 21). As discussed in the Company's Initial Brief, the time to address the significant underfunded pension position APS faces is now.

Staff and RUCO's arguments center around two main themes. First, they claim the magnitude of the Projected Benefit Obligation ("PBO") is not unusual and is driven by the current low interest rate environment. Unfortunately, there is no reason to believe that this underfunding in the plan over the last several years will go away or be reversed on its own. Second, they also claim there is an issue with intergenerational inequity. However, the PBO only considers **prior** employment service – not **future** employment service. The Company is asking customers to fund a liability that has already been incurred for services rendered on their

[15] In this case, the Company decreased pre-tax operating income by $43,695,000, which represents the Total Company figure. (APS Exhibit No. 56 at 24-25 [Rockenberger]; *Id.* at Attachment LLR-2-15).

behalf. (APS's Initial Brief at 61). In addition, customers will be fairly compensated during the time the Company "holds" any funds by providing a rate base return on the outstanding balance. Staff also asserts that this is inconsistent with regulatory precedent. Just because this specific approach to increase pension funding has not been used in other jurisdictions does not mean it should not be considered at this time given the seriousness of the current pension liability. (APS Exhibit No. 5 at 59-60 [Brandt]).

In short, it is both fair to customers and fiscally prudent for the Company and the Commission to address this pension underfunding issue now. Deferring the problem to a later date or hoping for the intervention of fortuitous events to solve the problem is not an appropriate regulatory response.

6. Annualized Property Tax Expense.

As discussed in its Initial Brief at 62-64, the Company asserts that the evidence in this case supports the Company's adjustment to reduce its pre-tax Test Year operating income in the amount of $15,031,000,[16] which represents the Company's ACC Jurisdictional revised calculation of annualized property tax expense. (*See* APS Initial Brief Exhibit 5, Schedule C-2, Column 19).

In its Initial Brief, Staff has argued that the Company's requested adjustment for property taxes is inconsistent with a similar adjustment related to Generation Production Tax Credits. In the instance of the property tax issue, the Company has recommended a calculation that includes known and measurable property tax values for 2007, as established by the Arizona Department of Revenue (based on year end 2005 property), and 2007 tax rates. On the other hand, the Company rejects the use of an estimated 2007 Production Tax Credit amount. The difference lies in the certainty of the former and the uncertainty of the latter.

The 2007 property values are known and measurable, as are property tax rates. In contrast, the Generation Production Tax Credit for 2007 is subject to a considerable amount of uncertainty that places it outside the parameters of known and measurable. Specifically, no one

[16] In this case, the Company decreased pre-tax operating income by $15,159,000, which represents the Total Company figure. (APS Exhibit No. 56 at 23 [Rockenberger]; *Id.* at Attachment LLR-2-12-13; *see also* APS Exhibit No. 57 at 20 [Rockenberger]; *Id.* at Attachment LLR-4-4RB).

knows the level of taxable "generation" income (if any – APS had none in 2005) for 2007 upon which the new tax credits would be calculated. Thus, there is no inconsistency in using information that meets the standard of being known and measurable, while at the same time not using other forecasted information that simply does not meet that test.

7. Annualized Depreciation And Amortization.

As discussed in its Initial Brief at 64, the Company asserts that the evidence in this case supports the Company's final adjustment to decrease its pre-tax Test Year operating income in the amount of $20,276,000,[17] which represents the Company's ACC Jurisdictional pre-tax adjustment to depreciation and amortization expense, based upon the technical update to the depreciation rates previously authorized in Decision No. 67744. (*See* APS Initial Brief Exhibit 4, Schedule C-2, Column 18).

In its Initial Brief, RUCO asserted that their calculation of the change in amortization rates is significantly different than that presented by the Company. APS strongly disagrees with RUCO's assertion that they have provided evidence that the Company's expense level is inappropriate. (RUCO's Initial Brief at 20). RUCO's calculation methodology lacked sufficient analysis or detail to properly normalize amortization expense, while the Company used a more precise method to make that calculation. (APS Exhibit No. 57 at 18-19 [Rockenberger]). The Company disputed RUCO's calculation as being non-representative of actual facts on numerous occasions (*See id.* at 18; Tr. Vol. XII at 2606 [Rockenberger]), and the Company witness explained in great detail the methodology that was used in calculating its adjustment The flawed logic presented in RUCO's calculation was graphically illustrated during the cross-examination of the RUCO witness, where a hypothetical algebra problem was utilized to demonstrate how the weighting of categories can in fact easily produce a result consistent with the Company's calculation and in conflict with that performed by RUCO. (Tr. Vol. XVIII at 3426-3429 [Diaz Cortez]).

RUCO further asserted that they were unable to perform a more complete analysis

[17] In this case, the Company decreased pre-tax operating income by $22,498,000, which represents the Total Company reduction. (APS Exhibit No. 56 at 20-22 [Rockenberger]; *Id.* at Attachment LLR-2-9).

because they had not been provided with sufficient data. The Company disputes this position because throughout this rate case, APS has made every effort to meet all of the requests for data from the parties. In the case of the information requested by RUCO in a data request, the Company provided information, and received no further request for additional data from RUCO. It was not until RUCO filed surrebuttal testimony that the Company became aware that RUCO did not feel it had received adequate information. In response, the Company provided additional information to RUCO, and the Company received no subsequent follow-up requests from RUCO for additional information. (APS Exhibit No. 58 at 3 [Rockenberger]).

8. **Demand Side Management ("DSM").**

Both Staff and RUCO dispute APS's pro forma revenue adjustment, which reflects the revenue impacts related to the Company's mandated DSM programs. (Staff's Initial Brief at 24; RUCO's Initial Brief at 13-15). Staff and RUCO both argued that the proposed adjustment for net lost revenues is not sufficiently known and measurable to be included in rates. (Staff's Initial Brief at 55). RUCO further argued that it would result in an improper mismatch of the time period over which the revenues were measured.

As discussed in detail in the Company's Initial Brief at 67-69, it is the Company's position that it is appropriate to set rates on conditions that will be present when new rates go into effect. Further, this "conservation adjustment," which was updated to include actual spending through third quarter 2006 and the projected amounts for the last three months of the year, was predicated upon known and measurable conditions, which is consistent with standard ratemaking policy. The Company's adjustment merely captures the impact of the DSM expenditures made during the Test Year and in 2006. (APS's Initial Brief at 67-69).

RUCO also asserted that the Settlement Agreement adopted in Decision No. 67744 specifically precluded the recovery of net lost revenues that were not reflected in the Test Year of a future application. (RUCO's Initial Brief at 13-14). RUCO does not argue that APS cannot seek to recover its DSM conservation adjustment as part of this general rate case, rather RUCO contends that the Test Year does not include DSM net lost revenues. RUCO believes that allowing the conservation adjustment for lost revenues that fall outside of the Test Year is contrary to Decision No. 67744. (RUCO's Initial Brief at 15). However, the "post-Test Year" revenue adjustment is used to normalize revenue for the "known and measurable" impact of the DSM programs. As such, the conservation adjustment is an appropriate method of setting rates based upon actual spending and further predicated upon known and measurable conditions that will be present when the new rates go into effect.

The Company is not proposing a year-by-year net lost revenue recovery mechanism, nor is it subtracting net lost revenues from its $48,000,000 DSM commitment, which was mandated in Decision No. 67744. The simple fact is that if APS cannot recover lost revenues from DSM programs in general rate proceedings, it will never be able to recover its full cost of service, which is something that was neither required by Decision No. 67744, nor consistent with the principles of cost-of-service regulation. (APS Exhibit No. 17 at 10-11 [Ewen]).

As discussed in its Initial Brief, the Company asserts that its final adjustment to decrease Test Year pre-tax operating income by $7,896,000, which represents both the Total Company and ACC Jurisdictional DSM pro forma adjustment to the Test Year operating costs, is correct and appropriate. (APS Exhibit No. 48 at 12 [Froggatt]; *Id.* at Attachment CNF 1-3; *see* APS Initial Brief Exhibit 5, Schedule C-2, Column 3).

9. "Lobbying" Costs.

The Company has fully discussed the support for its position regarding lobbying costs in its Initial Brief at 69-72, and will not reiterate them here. The Company is requesting that the Commission authorize recovery of only that portion of its lobbying expenses that benefit customers and utility operations. Because the Company has already allocated those items above and below the line, as appropriate, the Company opposes RUCO's recommendation that "above the line" lobbying expenses should be further split between customers and shareholders. (RUCO's Initial Brief at 19).

The Company agrees with Staff's recommendation that all future lobbying expenses should be recorded below the line and that any amount of those lobbying costs that the Company seeks to recover in future rates should be expressed as a pro forma adjustment to Schedule C-2. The Company has, in fact, has already made this change to its accounting system on a going-forward basis. However, Staff continues to fail to recognize that not all of the costs associated with the Company's Public Affairs Department are, in fact, lobbying expenses, and thus, the non-lobbying efforts of that department are not, nor should they be, recorded in FERC Account 426.4.

10. Incentive Compensation.

Staff has recommended a disallowance of costs associated with APS's stock-based incentive compensation plans, but supports the recovery of Test Year expenses associated with the Company's cash-based incentive compensation plans. (Staff's Initial Brief at 31). Without any formal analysis of the overall compensation levels of APS employees, RUCO has recommended an across-the-board reduction of the Company's cash incentive program. (RUCO's Initial Brief at 21).

The Company discussed in detail the support for its employee incentives and refuted Staff and RUCO's proposed disallowance in its Initial Brief at 72-73. APS's annual variable incentive plans and its long-term incentive plans are designed consistently with the competitive market practices, and are integral in providing a reasonable, competitive "total" compensation program at all levels of the organization. (APS Exhibit No. 51 at 4 [Gordon]). The elimination of any of these programs would significantly impair APS's ability to attract and retain employees critical to its successful ongoing operation. (*Id.*). In addition, the variable incentive plan is effective in aligning employees with its business objectives and reinforcing a high performance culture. (*Id.* at 4-5). Given the fact that neither Staff nor RUCO has offered any testimony contesting the Company's arguments or asserting that APS employee compensation levels are unreasonable (or for that matter, that the specific overall compensation elements at issue were excessive), neither Staff's recommended disallowance of the stock-based incentive program, nor RUCO's recommended disallowance of 20 percent of APS's employee cash incentive should be accepted.

11. SERP.

RUCO has proposed disallowance of some $4,700,000 from Test Year expense associated with the Company's SERP program. RUCO claims this adjustment was accepted in a

Southwest Gas rate proceeding. However, RUCO ignores the differences between the facts, as described by the Commission in the Southwest Gas case, and those that exist here. (Tr. Vol. III at 496-502 [Brandt]). Moreover, a SERP program is routinely made available by all companies, including utilities, that otherwise offer "qualified" benefit programs. (APS Exhibit No. 5 at 62-63 [Brandt]). SERP only places all APS employees, including management, on the same level with regard to retirement benefits. It is not some management "perk," but an important tool in retaining qualified professionals over the long term. (*Id.*). And, finally, so long as there has been no contention that overall management compensation is not excessive (and indeed, APS Exhibit No. 51 [Gordon] indicated precisely the opposite), it is the prerogative of management to design the specific compensation package of base salary, incentive pay and benefits – including SERP. (APS's Initial Brief at 74).

VI.
RATE DESIGN AND COST OF SERVICE

A. Phelps Dodge/AECC, Federal Executive Agencies ("FEA") And Distributed Energy Association Of Arizona's ("DEAA") Rate Design Proposals.

Phelps Dodge/AECC challenged APS's allocation of its energy costs based on a system average cost throughout the year. (Phelps Dodge/AECC's Initial Brief at 21). Current "across the board" energy-based charges are consistent with the rate designs agreed to in the Settlement Agreement and incorporated in Decision No. 67744. (APS Exhibit No. 71 at 3 [Rumolo]). During this proceeding, APS agreed that the energy allocation method proposed by AECC should be incorporated into the APS cost of service model. (APS Exhibit No. 70 at 9 [Rumolo]; Tr. Vol. XIV at 2803 [Rumolo]). Therefore, there is no longer disagreement between APS and Phelps Dodge/AECC on this issue.

Transmission costs are incurred by APS for retail sales based on charges found in the Open Access Transmission Tariff ("OATT") and are not the result of any allocation method in a retail rate case. (APS Exhibit No. 7 at 3 [Rumolo]). The rate designs agreed to in the Settlement Agreement and incorporated into Decision No. 67744 recovered transmission costs on an energy basis, with the same charge for all rate schedules. Similar to its position on energy cost allocation, APS agreed with the Phelps Dodge/AECC proposal because it would better align the recovery of transmission costs with the charges found in the APS OATT. (Tr. Vol. XIV at 2788-89 [Rumolo]; Tr. Vol. XV at 3069-70 [Higgins]).

DEAA continues to oppose demand rates and cost-based ratemaking for general service customers. Rate Schedule E-32, as approved in the Settlement Agreement, provides that customers under 20 kW (approximately 80 percent of E-32 customers) are billed on the basis of energy with capacity costs recovered in the energy charges – a fact that DEAA has yet to acknowledge.[18] (APS Exhibit No. 70 at 12 [Rumolo]). Furthermore, it should be noted that DEAA's membership consists of vendors and consultants and does not represent any segment of APS's customer classes. (Tr. Vol. XVII at 3185 [Murphy]). None of the parties to this case that represent actual general service customers and who would be impacted by the DEAA rate design proposals (*e.g.*, Phelps Dodge/AECC, FEA, Kroger) support energy only-based rates.

B. <u>Schedule Modifications.</u>

1. Schedule 1 – General Terms and Conditions.

APS has proposed to charge $75.00 per employee for certain services that can require multiple employees to provide. The Company objects to Staff's proposal to maintain the $75.00 per trip charge because the special services charged for under Section 2.2.4 are being performed outside of normal work hours, and usually require a crew with more than one person. The Company believes that Staff's recommendation will not appropriately recover the Company's costs and, therefore, will shift those costs to other customers. In addition, Staff's proposal will not send the proper price signal to customers as to the true costs of requesting extensive types of after-hours work. (APS Exhibit No. 38 at 29 [DeLizio]).

C. <u>Partial Requirements Service Offerings.</u>

APS continues to dispute DEAA's general rate design philosophy and its proposed partial requirements rate design philosophy that has no basis in cost causation. (*Id.* at 24). Furthermore, DEAA presented no evidence to support its claim that APS's demand and energy rate schedule components are not cost-based. (*Id.*). In response to DEAA's claims that the Company's partial

[18] This is the exact concept that DEAA espouses, and APS applies it to 80 percent of its general service customers. (APS Exhibit No. 70 at 12 [Rumolo]).

requirements rates are complicated and not easy to understand, the Company is proposing several changes to the partial requirement rate schedules and proposes to combine several of its partial requirements rates in order to make it easier for a customer with distributed generation to select the best option. (See APS's Initial Brief at 95-98 for specific partial requirement rate schedule changes proposed).

VII.
MISCELLANEOUS

A. Net Metering.

The Company is proposing a pilot program for its EPR-5 net metering rate. The purpose of this rate schedule is to encourage small customers to install renewable generation by providing an additional incentive, over and above the credit purchase under the Company's Solar Partners Incentive Program. (APS Exhibit No. 38 at 14-15 [DeLizio]). By setting a participation limit of 15 MW[19] and limiting it to customer-owned renewable resource generation facilities with a nameplate rating of 10 kW or less, the Company has targeted customers who have renewable energy facilities for the primary purposes of meeting their own energy needs, but may occasionally have excess energy to provide to the Company. (APS Exhibit No. 37 at 12 [DeLizio]).

By implementing EPR-5, APS will not recover all of the incurred transmission and distribution costs, and the Company will not recover non-avoidable charges, including the Competition Rules Compliance Charge ("CRCC"), Environmental Portfolio Standard ("EPS") Surcharge, DSM Cost Adjustment, PSA (for deferred fuel costs incurred during prior periods) and Transmission Cost Adjustment, from those customers choosing to be on this rate. (APS Exhibit No. 37 at 11 [DeLizio]). Thus, ironically, the net metering customers that are **directly** benefiting from the EPS, would not be funding it to the same extent as non-benefiting APS customers.

Under the Company's proposal, the incremental cost for this pilot net metering program would be funded through revenues collected through the current EPS surcharge. (*Id.* at 10). In

[19] Even with a 15MW cap, APS estimates a potential 5,000 3kW-unit customer installations. (Tr. Vol. VIII at 1811 [DeLizio]).

addition, infrastructure costs, such as changes to the customer billing systems, would also be funded through the EPS surcharge. (*Id.*). Revenue associated with transmission and distribution, as well as non-avoidable costs that are not recovered from EPR-5 customers, would also be funded by the EPS surcharge. (*Id.*).

Although Staff supported APS's recovery of uncollected fixed costs through the EPS, Staff would limit such recovery to the customer's excess generation,[20] not total generation. Staff also recommended that the limit on facility size be increased to 100kW. As noted in its Initial Brief, the Company's proposed recommendations strike a delicate balance between providing incentives to promote distributed renewable resources and the amount of such incentive being paid by other customers who would not be participating in the net metering program. (Tr. Vol. XII at 2429 [DeLizio]). APS will not repeat its arguments made in its Initial Brief, which justify the full recovery of these uncollected fixed costs. (*See* APS's Initial Brief at 107-115).

Solar Advocates have made several arguments: that the cap on individual system size should be increased to 2 MW; the overall program cap be increased to some higher level commensurate with an expanded Renewable Energy Standard ("RES") program; and that the rate should be made available to larger commercial customers. In addition, Solar Advocates are opposed to the recovery of uncollected fixed costs. Likewise, APS will not repeat its arguments made in its Initial Brief, which justify the Company's proposed 10 kW cap on the individual generator size and overall cap of 15MW. (*Id.*).

The Company disputes Solar Advocates' contention that the Company did not provide an adequate basis for recovery of uncollected fixed costs on the record or that such costs should not be recovered during a rate case. The Company prepared and entered an exhibit into the record entitled, "Net Loss Revenue Sample Calculation," which provides a detailed methodology as to how it calculates uncollected fixed costs (APS Exhibit No. 38, Attachment GAD-5RB [DeLizio]). As APS witness Greg DeLizio testified, to determine the Company's total revenue loss, the Company first calculates a net metering customer's energy use to determine the total revenue requirement based upon the installed system capacity and the energy generated by the

[20] The difference between the retail value of the kWh that's rolled over to the next month and the Company's avoided cost. (Tr. Vol. XIX at 3510-3511 [Keene]).

system. (Tr. Vol. XII at 2499 [DeLizio]). Next, the Company calculates the benefit of the systems that are being installed by pricing the energy produced at the Company's avoided costs (based upon the Palo Verde index). (*Id.*). To calculate the Company's uncollected fixed costs, the Company offsets its total lost revenue figure by the benefits. (*Id.*). According to Mr. DeLizio, the Company will track net metering customer usage and output to calculate the Company's uncollected fixed costs, based upon historical actual data. (*Id.* at 2559-2560).

The Solar Advocates ignored APS's testimony regarding the Company's rate case treatment of uncollected fixed costs (net loss revenues) pertaining to the Company's net metering proposal. The Company is promoting the use of distributed generation with its net metering pilot offering. There was no specific revenue adjustment made in the Company's filing to collect the unrecovered fixed costs that will necessarily result from the program. Rather, APS anticipated that the incremental costs for net metering will be funded through revenues collected through the current EPS surcharge. (APS Exhibit No. 37 at 10 [DeLizio]). As the program grows, the revenue loss associated with these uncollected fixed costs will continue to increase. There are two mechanisms that can provide for collection of these lost dollars:

1. Collect the revenues associated with the uncollected fixed costs through the EPS/RES surcharge (the Company's preferred method); or
2. Defer the revenues associated with the uncollected fixed costs for collection in a subsequent rate case.

Unless one of the methods above is adopted, APS will incur net revenue losses associated with its net metering program that cannot be recouped in future rate cases.

B. Renewable Procurement.

1. Renewables as a Hedge.

Western Resource Advocates ("WRA") proposed that the Company use renewable energy as a hedge against high natural gas prices. (WRA/SWEEP Post-Hearing Brief ("WRA/SWEEP's Initial Brief") at 5-8). In its 2004 settlement, the Company recognized that renewable energy could offset some of its need for generation from natural gas; however, this displacement currently comes at a high price. (APS Exhibit No. 47 at 2 [Dinkel]). There is a cost premium for any "hedge," and careful consideration of that cost is required. (*Id.*). The

Company continues to caution the Commission that the critical questions are whether additional amounts of renewable energy (additional to the RES and that required by Decision No. 67744) constitutes the most cost effective hedge in most applications, and, if not, whether such additional cost is reasonable for APS customers. (*Id.*).

2. Independent Evaluation / Solicitation Process.

Interwest Energy Alliance ("Interwest") continues to recommend that the Company be required to use an independent evaluator when evaluating future renewable Request for Proposals ("RFPs") and argues that the RES requirements for an independent audit of procedures is not sufficient to assure a fair RFP process. (*See* Post-Hearing Brief of Interwest Energy Alliance ("Interwest's Initial Brief") at 3-6). APS disagrees. The Staff Report recommending amendments to the EPS dated February 3, 2006, page 16, Section L, stated, "The proposed rules contain provisions that are intended to ensure the fairness of the resource selection process." (APS Exhibit No. 20 at 7 [Lockwood]). In addition, proposed RES Rule R14-2-1812(B)(5) retains this recommendation. APS believes that it is the Commission's intent to assure oversight of the procedures and processes associated with renewable resource selection. APS fully anticipates reporting on renewable energy activities in its annual EPS/RES compliance report and obtaining certification for all renewable resource selection. (*Id.*). This obviates the alleged need for any independent evaluator (other than the Commission itself).

3. Mandated Procurement Schedules.

Interwest also proposed that the Company conduct scheduled RFP's for renewable procurement. (*See* Interwest's Initial Brief at 6). Again, it is APS's position that renewable energy procurement is a management function, to be left to the discretion of the Company, so that it can have the flexibility it needs to best serve its customers. (APS Exhibit No. 19 at 8-9 [Lockwood]). Of course, any resource procured by APS would be subject to the ultimate review by the Commission in future rate proceedings.

C. DSM.

1. DSM Spending Should Remain At Its Current Level.

APS fully supports the DSM provisions of Decision No. 67744 and believes that DSM will provide benefits to APS customers when implemented in an efficient manner. Southwest Energy Efficiency Project ("SWEEP") continues to advocate for a very aggressive Energy Efficiency Standard ("EES") and savings target as opposed to a spending target, even though APS's DSM programs have only recently been approved by the Commission and little time has elapsed over which to assess the success of current programs. (APS Exhibit No. 32 at 4 [Orlick]). Time is still needed to get DSM programs up to speed, gauge progress, and evaluate achievements based upon the measurement, evaluation and research ("MER") process. (*Id.*). Some of the most cost effective program savings (and biggest program spending levels) come from new construction, and it may take one to two years before these projects are completed and able to be evaluated. (*Id.*). Both Staff and the Company believe it is premature to make substantial changes by implementing the EES or savings target. (*Id.* at 3; Staff Exhibit No. 17 at 3 [Anderson]).

In contrast, SWEEP argues that its proposed EES goals are reasonable and achievable. (*See* WRA/SWEEP's Initial Brief at 16). SWEEP makes this argument despite the fact that APS's current DSM spending level of $16,000,000 per year on energy efficiency represents approximately 0.75 percent of revenue, which according to the 2005 American Council for an Energy Efficient Economy ("ACEEE") Efficiency Program Compendium,[21] already exceeds the national average spending of 0.52 percent of revenue. (APS Exhibit No. 32 at 5-6 [Orlick]). SWEEP's proposed spending for APS would be equal to nearly 2.5 percent of revenue. (*Id.* at 6). Only three states nationally (Vermont, Massachusetts, Washington) spend more than 2 percent of revenue on energy efficiency, and these states have gradually increased funding over time. (*Id.*).

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[21] Dan York & Marty Kushler, *ACEEE's 3rd National Scorecard on Utility and Public Benefits energy Efficiency Programs: A National Review and Update of State Level Activity* 6 (2005).

2. SWEEP's Proposed Savings Goals Are Unrealistic.

SWEEP proposes that DSM energy efficiency funding for 2007 should be increased from about $25,000,000 to $38,000,000. It is noteworthy that SWEEP's savings goal incorporates an estimated funding level of 2 mills per kWh, which is a significant annual funding increase of $28,000,000 over current base rates, and a $22,000,000 increase over the target level of $16,000,000 per year. (APS Exhibit No. 32 at 7-8 [Orlick]). SWEEP's funding estimate is based on an assumption that APS will achieve DSM savings at an average cost of approximately one to two cents per lifetime kWh saved, which neglects to account for the full range of DSM costs. (*Id.* at 7). At the upper end of the range, two cents per lifetime kWh saved, the requisite funding level would increase from 2 mills to approximately 3.8 mills. (*Id.*). In addition, a final order in this case is not expected until April 2007, which makes SWEEP's proposal for such ambitious spending and savings increases for 2007 even more unrealistic.

3. The Conservation Adjustment Is Based Upon Known And Measurable Costs.

Staff and RUCO continue to oppose the Company's request for a conservation adjustment, because they believe it is based upon estimated costs that are not "known and measurable." (Staff Exhibit No. 16 at 9 [Anderson]; RUCO Exhibit No. 24 at 15 [Diaz Cortez]).

The Company reiterates that it is appropriate to set rates on conditions that will be present when the new rates go into effect. (APS Exhibit No. 17 at 10 [Ewen]). The Company modified its initial request, basing the rebuttal conservation adjustment on "actual spending ... and the amounts planned to be spent in the 4th quarter of this year [2006]." (APS Exhibit No. 18 at 9 [Ewen]). Most of that spending was for programs, such as the compact fluorescent light program, for which the savings are quantifiable. (Tr. Vol. VII at 1404 [Orlick]). As such, the Company's calculations are not estimates, but "known and measurable" adjustments to the Test Year. (Tr. Vol. V at 1095 [Ewen]). The failure to allow APS to recover its lost revenues from DSM programs by reflecting such revenue losses in general rate proceedings will simply prevent the Company from currently recovering its full cost of service. (APS Exhibit No. 17 at 10 [Ewen]).

4. Demand Response.

The Company agreed with Staff and RUCO that Demand Response programs have the ability to benefit the system, and concurred with their findings that a study group should be assembled to evaluate various Demand Response options. The Company remains opposed to Staff's proposal that the Company submit a demand response feasibility study within eight months of the Commission's decision in this rate case, even with Staff's proposal not to object to an extension request. (Staff's Initial Brief at 70). As set forth in APS's Initial Brief, the Company believes that truly effective Demand Response programs cannot be implemented, analyzed, and introduced to all customers in such a short amount of time. (APS's Initial Brief at 123). Eight months is an insufficient amount of time to implement the rates and then evaluate customer response. Indeed, a time-of-use rate implemented in this eight-month window will bypass a portion of the summer months, and it would be unreasonable for APS to evaluate its proposed Demand Response programs with such a small sampling of data. (APS Exhibit No. 47 at 7 [Dinkel]).

D. <u>Rate Stabilization Fund</u>

Although the potential establishment of a rate stabilization fund was not an issue raised by any of the Parties in this case, the Commission had questions regarding this issue. (*See* Tr. Vol. I at 88-92 [Mayes]; Tr. Vol. II at 342-46 [Hatch-Miller]; Tr. Vol. XX at 3748-49 [Gleason]; Staff's Initial Brief at 71). Although APS is dubious of Staff's characterization as to the "potential benefits" of any such mechanism, the Company finds itself in essential agreement with Staff's analysis of the issue. The Company believes that rather than establishing a rate stabilization fund, any savings it has achieved to its regulated cost of service should be reflected in current rates so customers pay less now, rather than more later. Such a philosophy is reflected in the current filing. (Tr. Vol. II at 348 [Wheeler]; *see also* APS letter to Commissioner Mayes dated October 9, 2006 at 2). As explained in a letter from Mr. Jack Davis to the Commission dated August 1, 2006, APS does not have any "excess" revenues (unlike SRP or a legislative "rainy day" fund) to devote to such a fund. Finally, in response to an inquiry from Chairman

Hatch-Miller (*Id.* at 345-46 [Hatch-Miller]), and after researching this issue, the Company did not find any Commission Decisions where a company was ordered to establish such a fund.

VIII.
PALO VERDE PRUDENCE REVIEW

A. Introduction.

Staff's Initial Brief highlights its failure to present "clear and convincing evidence" of imprudence necessary to rebut the presumption of prudence to which APS's actions are entitled. [A.A.C. R14-2-103(A)(3)(l)]. Staff's case consists of unsupported assertions by its witness Dr. William Jacobs, including assertions that, as in the case of the principal outage at issue here, are flatly contrary to the statements of NRC's Regional Administrator in response to questioning by this Commission. Thus, the evidence does not support any finding of imprudence, but even if the Commission were to conclude otherwise, there are substantial corrections and offsets to Staff's proposed disallowances that must be made. Finally, Staff has not made a case for any performance standard, much less the penalty-only, Palo Verde-only standard it has proposed.

B. Staff Has Failed To Demonstrate That Any Of The 2005 Outages Were The Result Of APS Imprudence.

1. October Refueling Water Tank ("RWT") Outage.

Staff's sole argument in its Initial Brief regarding the October RWT outage is that APS "should have known that air entrainment damage to pumps is a safety concern" and that APS should have identified the question of air entrainment in the RWT system before the NRC. (Staff's Initial Brief at 49). Staff apparently misunderstands the nature of the air entrainment question the NRC inspector raised. APS did know about the potential for air entrainment and did account for it in the RWT system. As Dr. Mattson testified, "the designers of the plant and NRC were aware, back in the 1970s, of the potential for air entrainment in the RWT suction line, and requirements had been established in the design that were met by plant construction to foreclose this possibility." (APS Exhibit No. 88 at 6-7 [Mattson]). The question the NRC inspector raised, however, was not a general question relating to air entrainment, but a very specific question never asked before related to dynamic as opposed to static flow analysis.[22] (*Id.* at 4).

As for Staff's contention that APS "instead of the NRC—should have identified this issue because of the NRC's yellow finding in 2004 on a related issue," Staff fails to address how the issues were related. (Staff's Initial Brief at 49). In fact, the yellow finding is substantially different from the issues surrounding the RWT. The yellow finding was issued to APS for maintaining a section of piping dry when the design required the piping to be filled with water (APS Exhibit No. 87 at 40 [Mattson]), while the new question the NRC inspector asked was whether the Palo Verde design adequately addressed air entrainment (using a dynamic flow analysis), not whether APS had followed the design. (*Id.* at 53; APS's Initial Brief at 156). In its evaluation of the yellow finding, APS determined that the RWT system did, in fact, follow the approved design (Tr. Vol. XXVIII at 5188-91 [Levine]; APS's Initial Brief at 155-56). Until the NRC inspector raised the dynamic flow question in October 2005, APS had no reason to question the adequacy of the Palo Verde design.

Moreover, Staff's unsupported argument that APS should have addressed the air entrainment question before the NRC did so is rebutted by the presentation of Regional Administrator Mallett, the senior NRC official in Region IV (Palo Verde's region). When he appeared before this Commission and was asked whether APS should have anticipated his inspector's RWT air entrainment question, Dr. Mallett described it as a "new question," and clearly stated that the NRC did "evaluate whether [APS] should have found it before us" and that "we didn't determine that [APS] should have found it beforehand." (APS Exhibit No. 104 at 43, 45-46; APS's Initial Brief at 152, 154). Staff's brief fails to even **mention** these statements of the senior NRC official responsible for oversight of Palo Verde, each of which is directly contrary to Staff's position.

Finally, even if APS **had** identified the air entrainment issue in response to the yellow finding, an outage for identical reasons would still have occurred, because the yellow finding

[22] Staff further demonstrates its misunderstanding of the issue when it states, "The Company could not demonstrate to the NRC that air entrainment was not occurring" and "threatened safe operations." (Staff's Initial Brief at 49). The potential for air entrainment does not occur during operations but would arise only in a hypothetical accident scenario that the NRC inspector wanted analyzed. Ultimately, after the analysis was completed, no changes were made to the RWT system before restarting from this October outage, and no changes have been made to the RWT system since then. (APS Exhibit No. 88 at 4 [Mattson]).

was not issued until April 2005. (APS Exhibit No. 88 at 6 [Mattson]; Tr. Vol. XXVI at 4966 [Mattson]; APS's Initial Brief at 157). Furthermore, the economic impact on Arizona ratepayers would have been much higher had the outage occurred during peak summer months or when all three units were operating. (Tr. Vol. XXVI at 4974 [Mattson]).

2. August Reactor Trip.

Staff's discussion of the August reactor trip in its Initial Brief supports the conclusion that this outage was caused by the actions of an individual operator, without management knowledge or approval. (Staff's Initial Brief at 47-48). Staff stated that "the steam generator **operator failed to obtain supervisory approval** before switching to manual operation of the digital feedwater control system ("DFWCS") . . . resulting in a high steam generator level and a consequent reactor trip." (*Id.* (emphasis added)).

Staff has not provided any evidence to support its assertion that APS knew there was a problem with the DFWCS system prior to the outage. (*Id.*). Staff's brief only cites Dr. Jacobs' unsupported statements in his Surrebuttal Testimony. (*Id.* at 48). Staff's argument that APS conceded that operators claimed that the DFWCS was unreliable does not support a finding of imprudence because the operators made these statements following the outage, and Staff presented no evidence demonstrating that APS should have been aware of these unexpressed operator concerns earlier. (*Id.* at 47-48). Indeed, when questioned at the hearing about his testimony that the operators' concerns were "well known and long standing," Dr. Jacobs was unable to provide any evidence showing that APS management had knowledge of these concerns. (Tr. Vol. XXIX at 5362, 5395-97 [Jacobs]; APS's Initial Brief at 162-63). Therefore, Staff's conclusion that APS failed to address a known problem with the DFWCS, and that such alleged failure demonstrates imprudence, is unsubstantiated. (Staff's Initial Brief at 48).

3. March Diesel Generator Outage.[23]

The essence of Staff's argument is that because the diesel generators are important pieces

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[23] APS agrees with Staff's decision to not recommend any disallowance or an adjustment to base fuel costs for the March diesel generator governor outage. (Staff's Initial Brief at 46; APS's Initial Brief at 164). The parties continue to discuss this outage to address Commissioner Mayes' comment that the prudence of this outage might be relevant to whether the Commission should adopt a nuclear performance standard.

of equipment, albeit 100% redundant,[24] the fact that one part on one diesel generator failed must mean that "the Company did not treat the EDGs with the degree of care appropriate to the significance of this particular piece of equipment." (Staff's Initial Brief at 47). Of course, as Mr. Denton testified, "there are literally hundreds of pieces of equipment in a nuclear plant equally as important." (APS Exhibit No. 90 at 2 [Denton]). Staff's argument attempts to impose strict liability on the Company, *i.e.*, because the part failed, the Company must have been imprudent. This position is inconsistent with the prudence standard, and when that standard is applied, there can be no doubt that APS acted prudently.

Palo Verde properly stored the governor according to the manufacturer's recommendations (APS Exhibit No. 89 at 15-16 [Denton]), properly inspected the governor prior to installation (*Id.* at 16-17), and properly sampled the governor oil based on information reasonably available at the time. (APS Exhibit No. 95 at 11 [Levine]; APS's Initial Brief at 164-67). Other than its strict liability argument, Staff has provided no evidence to rebut any of APS's testimony regarding these topics. Rather, Staff uses hindsight and contends that had Palo Verde stored the governor with oil, as it now does, this outage would have been avoided. (Staff's Initial Brief at 47). In addition to offering no proof to support this contention, Staff's argument is in conflict with the NRC's caution to public service commissions about "penalizing a utility for improving its own procedures or methods of operations." (APS Exhibit No. 101 at 3; APS's Initial Brief at 163). Thus, the circumstances of this outage provide no support for imposition of a nuclear performance standard, even if such a standard was otherwise appropriate.

C. <u>Staff Failed To Apply Certain Offsets And Corrections To Its Recommended Disallowance.</u>

Staff calculated a total recommended disallowance of $16,186,000, including $13,757,000 for alleged imprudent outages during the PSA effective period, $2,103,000 for reduced margins on off-system sales, and interest. (Staff's Initial Brief at 46; Staff Exhibit No. 46 at 49 [GDS Report]). As discussed above, Staff has not demonstrated that any of the outages were the result of APS imprudence, but even if the Commission agrees with Staff about the

[24] Mr. Denton testified that "the failure of one machine to start is fully backed up by another diesel and a completely redundant set of equipment." (APS Exhibit No. 90 at 2 [Denton]).

outages, Staff's proposed disallowance is overstated.

First, Staff has not even addressed the evidence demonstrating that had Unit 2 not been shut down in October 2005 to address the RWT issue, Unit 2 still would have had to shut down to perform maintenance on Unit 2 Reactor Coolant Pump ("RCP") oil seals. (APS Exhibit No. 95 at 5-7; *Id.* at Attachment JML-1RJ; APS's Initial Brief at 157-58). In fact, Staff characterized maintenance on RCP oil seals in Unit 1 for identical reasons during an August outage as "unavoidable." (Staff's Initial Brief at 47). APS calculated that the maintenance on the Unit 2 RCPs in October avoided $5,100,000 in replacement power costs (APS Exhibit No. 17 at 21-22 [Ewen]), which should be offset from any disallowance by the Commission for the October Unit 2 RWT outage.

Second, Staff witness Jacobs conceded that his calculation of $2,103,000 for reduced margins on off-system sales was inaccurate, because not all 187,000 MWh used in his calculation would have actually been sold. (Tr. Vol. XXIX at 5304 [Jacobs]; APS's Initial Brief at 176). APS witness Ewen provided a more detailed calculation, which Dr. Jacobs stated was "probably the more accurate way to do it," that concluded that APS lost at most 9,000 MWh of off-system sales, resulting in a maximum reduced margin of $322,000. (APS Exhibit No. 17 at 20-21 [Ewen]). This amount should be reduced further for any of the outages that the Commission determines not to be imprudent. (APS Exhibit No. 103; APS's Initial Brief at 177-78).

Third, Staff's Initial Brief similarly does not address the fact that Dr. Jacobs did not correctly apply the 90/10 sharing in his calculations by discounting the normal amount of outages in base rates. (APS's Initial Brief at 178). Dr. Jacobs' methodology results in APS having expensed twice the same amount of $515,000. (APS Exhibit No. 17 at 24 [Ewen]; APS's Initial Brief at 178). Therefore, Staff's recommended disallowance should be reduced by $515,000.

Finally, the only offset that Staff addresses in its Initial Brief relates to the excellent performance of APS's coal plants in 2005. (Staff's Initial Brief at 49-50). In 2005, APS's coal plants set an all-time record for capacity factor. (APS Exhibit No. 17 at 25 [Ewen]; APS's Initial

Brief at 149). Staff's arguments that superior coal plan performance is "external and unrelated" to the Palo Verde outages and that Palo Verde "replacement power costs are unaffected by the superior performance of the coal plants" (Staff's Initial Brief at 49-50) fail to recognize that APS customers are impacted by the performance of the entire APS baseload generation system, rather than by just one plant. As Mr. Ewen testified, the record coal plant capacity factor in 2005 prevented more than 300 gigawatt hours of additional outage time and the resulting replacement power costs that would have been incurred had those plants merely performed as expected, reducing fuel costs by $10,000,000. (Tr. Vol. XXVIII at 5223 [Ewen]). These savings are not reflected in the replacement power costs for Palo Verde due to the methodology used by APS in calculating these costs. (*Id.* at 5222; APS's Initial Brief at 149). Thus, as Mr. Ewen demonstrated, APS's superior coal plant performance in 2005 directly reduced the added fuel costs from reduced performance at Palo Verde, and, therefore, Staff is incorrect in stating that an offset for these avoided costs would result in a "double count" of coal plant performance. (Staff's Initial Brief at 50). Accordingly, any disallowance by the Commission should be reduced by $10,000,000. (APS's Initial Brief at 149). Similarly, comparing APS's outstanding coal plant performance in 2005 against its industry peers demonstrates an even more dramatic savings of $27,492,000, which entirely eliminates any disallowance were the Commission to determine that any outages were imprudent. (*Id.*).

D. <u>Not Only Do Staff's Arguments Fail To Support Implementation Of Staff's Proposed Nuclear Performance Standard ("NPS"), They Do Not Support Implementation Of Any NPS.</u>

Contrary to Staff's claims, APS has not "tentatively expressed willingness to agree" to a NPS. (Staff's Initial Brief at 51). Rather, APS has shown that a NPS is unnecessary and inappropriate, and lacks factual basis. As APS demonstrated in its Initial Brief, Staff has not provided sufficient information or guidance to implement any performance standard at this time. (APS's Initial Brief at 169-71). For example, Staff has not reviewed performance standards from other jurisdictions or even earlier standards in Arizona adopted by this Commission. (*Id.* at 169). In fact, Staff witness Jacobs was unaware that this Commission had adopted an earlier performance standard – a standard which was substantially different than the standard currently proposed by Staff. (Tr. Vol. XXIX at 5288 [Jacobs]; Decision No. 54247 at 11-16 (November 28, 1984)). Additionally, Staff's proposed performance standard does not address, among other things, caps, differences in refueling cycles, calculation of a target value, or inclusion of safety-related attributes. (APS's Initial Brief at 169-70). As Mr. Fitzpatrick testified, these elements need to be "hammered out" (Tr. Vol. XXVII at 509 [Fitzpatrick]), and, therefore, this proceeding has not provided sufficient information for this Commission to adopt a performance standard. However, if the Commission nonetheless determines to implement a performance standard for APS, it should include attributes that are either missing from Staff's proposal or that are substantially different (*e.g.*, rewards as well as penalties, and inclusion of all baseload plants). (APS's Initial Brief at 168-75).

Staff argues that a performance standard would apply "appropriate pressure to the Company to improve its performance." (Staff's Initial Brief at 51). This claim contradicts Staff witness Jacobs' recommendation to the Georgia Commission to terminate a NPS and his testimony in that proceeding that a NPS would have no effect on plant operations. (APS Exhibit No. 100; Tr. Vol. XXIX at 5286 [Jacobs]; APS's Initial Brief at 168). Moreover, any "pressure" that such a standard might create would not be "appropriate." As the NRC's Policy Statement declares: "an incentive program could directly or indirectly encourage the utility to maximize measured performance in the short term at the expense of plant safety (public health and safety)." (APS Exhibit No. 101; APS's Initial Brief at 169).

Staff also argues that a NPS at Palo Verde is consistent with APS's Performance Improvement Plan goal of being a top performing nuclear facility. (Staff's Initial Brief at 51). However, the fact that APS's goal is to be an above average performer does not justify penalizing the Company if Palo Verde performance ever drops below average in the absence of demonstrated imprudent management.

Finally, Staff's argument that a performance standard should only include nuclear units, and not coal units, is deficient. First, this argument contradicts the NRC's Policy Statement, which states that a performance standard should incorporate "performance measures of the entire system..." (APS Exhibit No. 101 at 4; APS's Initial Brief at 173). Second, nuclear units are similar to coal units because both provide baseload power and both "enjoy a significant cost advantage over purchased power and have the potential to confer a substantial benefit on APS' customers when run successfully." (APS Exhibit No. 91 at 9-10 [Fitzpatrick]; APS's Initial Brief at 149). Third, although Staff states that nuclear and coal plants "use different operational and safety processes, are subject to different forms of regulation, and have costs that are unrelated and not directly comparable," Staff provides no reasoning for why any of these alleged differences would preclude coal units from being included in a performance standard.[25] (Staff's Initial Brief at 51). Indeed, this Commission has already adopted a performance standard in the past that included both nuclear and coal generating units (Decision No. 54247 at 16 [November 28, 1984]), and the Commission is capable of doing the same in this proceeding if it determines that a performance standard should be imposed.

IX.
CONCLUSION

APS has presented overwhelming evidence in this rate application to support its requested rate increase. APS respectfully submits that the requested increase is fully warranted and amply justified by increased fuel costs, increased operating costs, and the lack of opportunity for the Company to earn a fair and reasonable return on its invested equity in recent years.

APS has demonstrated that its financial metrics have declined in recent years and are now at the threshold of non-investment "junk bond" status. APS has also shown that, due to the lag associated with recovery of huge capital expenditures averaging approximately $900 million per year, it has consistently failed to earn its allowed ROE in the past several years and consistent under-earning of the Company is the result of its inadequate rates, which are not sufficient to cover the Company's increasing costs of service, or the related financial and capital obligations associated with its growing customer base.

[25] While some attributes of a performance standard would be different for coal plants and nuclear plants, *e.g.*, different evaluation cycles (APS's Initial Brief at 173), these differences do not disfavor inclusion of coal units in such a standard.

Establishing an adequate Base Fuel Cost and adjusting the PSA in the manner proposed by the Company or adopting the prospective PSA mechanism embraced by Staff would be significant steps in the right direction. By themselves, however, they are not sufficient to address the cost recovery and under-earnings issues raised by the Company. Indeed, the proposals by Staff and RUCO to cut rates with respect to the Company's non-fuel costs would significantly undermine the Company's efforts to improve its financial metrics (and thereby avoid a slide to "junk bond" credit status), and would send an extremely negative message to the investment community and the credit rating agencies.

The Company respectfully submits that now is the time for the Commission to address the issues of cost recovery and under-earnings raised by the Company. In this regard, the Company urges the Commission to consider the proposals of CWIP in rate base, accelerated depreciation, earnings attrition allowance and other techniques discussed herein as ways to improve the Company's financial metrics and ensure that the Company can continue to meet the needs of the country's fastest growing service area.

With respect to costs associated with outages at Palo Verde in 2005, the Company respectfully submits that it has demonstrated that it acted prudently with respect to each of those outages, and therefore no disallowances are appropriate. The full amount of the requested Step 2 PSA Surcharge should be granted coincident with the new rates established in this proceeding.

RESPECTFULLY SUBMITTED this 16th day of February, 2007.

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PROFORMA JURISDICTIONAL ALLOCATION CHART
Difference between APS and Staff 1/

Proforma Col. A	APS Allocator for ACC Jurisdiction Col. B	Staff Allocator for ACC Jurisdiction Col. C
C.1. - Reverse Estimated Conservation Impact from DSM	100.000% Retail Only	100.000% Retail Only
C.2. - Schedule 1 Rate Changes	100.000% Retail Only	99.120%
C.3.a. - Reduction in Fuel & Purchased Power	100.000% Retail Only	100.000% Retail Only
C.3.b. - Off-System Sales Margins	98.389% Energy Allocator	98.389% Energy Allocator
C.4. - Eliminate M&T Revenues & Purchased Power Expenses	98.389% Energy Allocator	98.389% Energy Allocator
C.5. - Eliminate M&T O&M Expenses	98.389% Energy Allocator	94.212% Wages & Salaries Allocator
C.6. - Pension Expense Adjustment	94.212% Wages & Salaries Allocator	94.212% Wages & Salaries Allocator
C.7. - Post Retirment Medical Benefits Adjustment	94.212% Wages & Salaries Allocator	94.212% Wages & Salaries Allocator
C.8. - Eliminate Additional Marketing Expenses	94.212% Wages & Salaries Allocator	100.000% Retail Only
C.9. - Eliminate Non-Recurring Shared Services Costs	94.212% Wages & Salaries Allocator	94.212% Wages & Salaries Allocator
C.10. - Eliminate Silverhawk Related Legal Expenses	98.847% Demand Allocator	94.212% Wages & Salaries Allocator
C.11. - Eliminate Sundance Non-Routine Maintenance Expense	98.847% Demand Allocator	98.847% Demand Allocator
C.12. - Eliminate Non-Recurring Tax Research Costs	98.847% Demand Allocator	94.212% Wages & Salaries Allocator
C.13. - Eliminate Stock Based Incentive Compensation	94.212% Wages & Salaries Allocator	94.212% Wages & Salaries Allocator
C.14. - Eliminate Bark Beetle Amortization	100.000% Retail Only	100.000% Retail Only
C.15. - Eliminate Lobbying Costs Charged Above-the -Line	94.212% Wages & Salaries Allocator	94.212% Wages & Salaries Allocator
C.16. - Nuclear Fuel/ISFSI Amortization Expense	98.389% Energy Allocator	98.389% Energy Allocator
C.17. - Eliminate Estimated Increase in 2007 PWEC Property Taxes	98.847% Demand Allocator	98.847% Demand Allocator
C.18. - Production Tax Credit Adjustment	98.847% Demand Allocator	98.847% Demand Allocator
C.19. - Interest Synchronization Deduction Adjustment	(Included in C.20. Adjustment)	(Included in C.20. Adjustment)
C.20. - Correct COSS Income Tax Expense	94.833% Composite Income Tax Allocator	100.000% Retail Only
C.21. - PV 1 Steam Generator Depreciation Expense	98.847% Demand Allocator	98.847% Demand Allocator
C.22. - Interest on Customer Deposits	100.000% Retail Only	100.000% Retail Only
C.23. - RUCO's Incremental Property Tax Adjustment	99.123% Composite Property Tax Adjustor	99.123% Composite Property Tax Adjustor

1/ RUCO allocated proformas using three composite allocation factors. These were 111.96% for RUCO proposed O&M adjustments, 89.06% for depreciation and amortization adjustments and 85.55% for "Other Taxes," i.e., property taxes.

Figure 5-3

Summary of Lag in Payment of Expenses and Investor Funds Advanced for Operations for the Year Ended December 31, 19X2 (Thousands of Dollars)

Line No.	Description	Amount	Average Lag Days	Dollar Days
1	Fuel (Figure 5-4)	$ 550,415	16.83	$ 9,263,520
2	Purchased and interchanged power	194,547	35.20	6,848,070
3	Wages and salaries	121,797	11.85	1,443,292
4	Other operating and maintenance expenses (See Figure 5-5 for an illustration of the amounts included in this line.)	202,483	24.66	4,992,353
5	Depreciation and amortization	130,159		
6	Income taxes			
	Federal—net current	8,449	59.00	498,491
	State	58	212.00	12,296
	Deferred income taxes	13,450		
7	General taxes			
	FICA and unemployment	7,709	23.22	178,991
	Gross receipts	59,634	76.06	4,536,041
	Property	28,462	153.07	4,356,639
	Other	8,495	34.32	291,542
8	Total	$1,325,658	24.46	$32,421,235
9	Number of days in year	365		
10	Average daily operating expenses	3,632		
11	Lag in receipt of revenue (Figure 5-2)		45.10	
12	Excess lag in receipt of revenues over lag in payment of operating expenses (Line 11 minus line 8)		20.64	

13	Cash working capital required for all operating and maintenance expenses (Line 10 times Line 12)	$74,964
14	Less average withholding and utility tax on hand	2,441
15	Net investor funds advanced for operating expenses	$72,523

Figure 5-4

Calculation of Fuel Expense Lag for the Year Ended December 31, 19X2 (Thousands of Dollars)

Line No.	Description	Amount	Average Lag Days	Dollar Days
1	Fossil fuel	$583,050	15.59	$ 9,088,420
2	Nuclear fuel	37,209	29.64	1,102,749
3	Other fuel	18,220	30.43	554,468
4	Total excluding fuel deferral.	638,479	16.83	10,745,637
5	Deferred fuel.	(88,064)	16.83	(1,482,117)
6	Total fuel	$550,415	16.83	$ 9,263,520